

Chapter IV: Technological Feasibility

A. Feasibility of Tier 2 Exhaust Emission Standards for Vehicles

1. NMOG and NO_x Emissions from Gasoline-Fueled Vehicles

Emission control technology has evolved rapidly since the passing of the CAA Amendments of 1990. Emission standards applicable to 1990 model year vehicles required roughly 90 percent reductions in exhaust HC and CO emissions and a 75 percent reduction in NO_x emissions compared to the uncontrolled emissions. Some vehicles currently in production show overall reductions in these three pollutants of more than 99 percent. These vehicles' emissions are well below those necessary to meet the current federal Tier 1 and even California LEV standards.

A number of technological advances and breakthroughs have allowed these significant emission reductions to occur without the need for expensive, exotic equipment and fuels. For example, ARB originally projected that many vehicles would require electrically heated catalysts to meet their LEV program requirements. Today, no manufacturer is expected to use these devices to comply with the LEV program requirement. EPA projected that alternative fuels, such as methanol or natural gas, might be needed to meet these low emission levels. Today, while vehicles using these alternative fuels are capable of meeting the California LEV requirements, so are vehicles fueled with gasoline.

The most significant improvements which have facilitated these low emission levels have been to traditional catalysts, which now warm up very rapidly and are substantially more durable than past technology, and to fuel metering, which is more precise and accurate than previous systems. Improvements have also been made to base engine designs, which have resulted in lower engine-out emissions. Reduction of combustion chamber crevice volumes and oil consumption are examples of improvements to base engine designs. Perhaps most important of all, emission control calibrations continue to become more refined and sophisticated.

Table IV-1 below lists specific types of emission controls which EPA projects will be needed in order for the affected vehicles to meet the final Tier 2 standards. It is important to point out that all of the following technologies would not necessarily be needed to meet the Tier 2 standards. The choices and combinations of technologies will depend on several factors, such as current engine-out emission levels, effectiveness of existing emission control systems, and individual manufacturer preferences. In some cases, such as the need for increases in catalyst volume and precious metal loading, EPA believes that most, if not all, cars and trucks will use the specified emission control technique.

**Table IV-1. Emission Control Hardware and Techniques
Projected to Meet Tier 2 Vehicle Standards**

<i>Emission Control Technologies</i>	
Fast Light-Off Exhaust Gas Oxygen Sensor	Injection of Air into Exhaust
Universal Exhaust Gas Oxygen Sensor	Heat Optimized Exhaust Pipe
Retarded Spark Timing at Start-Up	Leak-Free Exhaust System
More Precise Fuel Control	Close-Coupled Catalyst
Faster Microprocessor	Improved Catalyst Washcoats
Individual Cylinder Air-Fuel Control	Increased Catalyst Volume and PGM Loading
Manifold with Low Thermal Capacity	Full Electronic Exhaust Gas Recirculation
Air-Assisted Fuel Injection	Engine Modifications

a. Technology Description

The following descriptions provide an overview of the latest technologies capable of reducing exhaust emissions. The descriptions will also discuss the state of development and current production usage of the various technologies. The technology descriptions are divided into four categories - base engine improvements, improved fuel control, improved fuel atomization, and improved catalyst performance.

i. Base Engine Improvements

There are several design techniques that can be used for reducing engine-out emissions, especially for HC and NO_x. The main causes of excessive engine-out emissions are unburned HC's and high combustion temperatures for NO_x. Methods for reducing engine-out HC emissions include the reduction of crevice volumes in the combustion chamber, reducing the combustion of lubricating oil in the combustion chamber and developing leak-free exhaust systems. Leak-free exhaust systems are considered to be base engine improvements because any modifications or changes made to the exhaust manifold can directly affect the design of the base engine. Base engine control strategies for reducing NO_x include the use of "fast burn" combustion chamber designs, multiple valves with variable-valve timing, and exhaust gas recirculation.

Combustion Chamber Design

Unburned fuel can be trapped momentarily in crevice volumes (i.e., the space between the piston and cylinder wall) before being subsequently released. Since trapped and re-released fuel can increase engine-out HC, the reduction of crevice volumes is beneficial to emission performance. One way to reduce crevice volumes is to design pistons with reduced top “land heights” (The distance between the top of the piston and the first piston ring). The reduction of crevice volume is especially desirable for vehicles with larger displacement engines, since they typically produce greater levels of engine-out HC than smaller displacement engines.

Another cause of excess engine-out HC emissions is the combustion of lubricating oil that leaks into the combustion chamber, since heavier hydrocarbons in oil do not oxidize as readily as those in gasoline. Oil in the combustion chamber can also trap gaseous HC from the fuel and release it later unburned. In addition, some components in lubricating oil can poison the catalyst and reduce its effectiveness. To reduce oil consumption, vehicle manufacturers will tighten tolerances and improve the surface finishes of cylinders and pistons, improve piston ring design and material, and improve exhaust valve stem seals to prevent excessive leakage of lubricating oil into the combustion chamber.

As discussed above, engine-out NO_x emissions result from high combustion temperatures. Therefore, the main control strategies for reducing engine-out NO_x are designed to lower combustion temperature. The most promising techniques for reducing combustion temperatures, and thus engine-out NO_x emissions, are the combination of increasing the rate of combustion, reducing spark advance, and adding a diluent to the air-fuel mixture, typically via exhaust gas recirculation (EGR). The rate of combustion can be increased by using “fast burn” combustion chamber designs. A fast burn combustion rate provides improved thermal efficiency and a greater tolerance for dilution from EGR resulting in better fuel economy and lower NO_x emissions. There are numerous ways to design a fast burn combustion chamber. However, the most common approach is to induce turbulence into the combustion chamber which increases the surface area of the flame front and thereby increases the rate of combustion, and to locate the spark plug in the center of the combustion chamber. Locating the spark plug in the center of the combustion chamber promotes more thorough combustion and allows the ignition timing to be retarded, decreasing the dwell time of hot gases in the combustion chamber and reducing NO_x formation. Many engine designs induce turbulence into the combustion chamber by increasing the velocity of the incoming air-fuel mixture and having it enter the chamber in a swirling motion (known as “swirl”).

Improved EGR Design

One of the most effective means of reducing engine-out NO_x emissions is exhaust gas recirculation. By recirculating spent exhaust gases into the combustion chamber, the overall air-fuel mixture is diluted, lowering peak combustion temperatures and reducing NO_x. As

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discussed above, the use of high swirl, high turbulence combustion chambers can allow the amount of EGR to be increased from current levels of 15 to 17 percent to levels possibly as high as 20 to 25¹ percent, resulting in a 15 to 20 percent reduction in engine-out NO_x emissions.

Many EGR systems in today's vehicles utilize a control valve that requires vacuum from the intake manifold to regulate EGR flow. Under part-throttle operation where EGR is needed, engine vacuum is sufficient to open the valve. However, during throttle applications near or at wide-open throttle, engine vacuum is too low to open the EGR valve. While EGR operation only during part-throttle driving conditions has been sufficient to control NO_x emissions for most vehicles in the past, more stringent NO_x standards and emphasis on controlling off-cycle emission levels may require more precise EGR control and additional EGR during heavy throttle operation to reduce NO_x emissions. Some manufacturers use a mechanical back-pressure system that measure EGR flow (via delta pressure across an orifice) rather than inferring flow from the EGR pintle position. This system uses electronic control of the vacuum actuation and has very precise control. Many manufacturers are now using electronic EGR in place of mechanical back-pressure designs. By using electronic solenoids to open and close the EGR valve, the flow of EGR can, in some cases, be more precisely controlled.

While most manufacturers agree that electronic EGR gives more precise control of EGR flow rate, not all manufacturers are using it. Numerous LEV vehicles certified for the 1998 model year still use mechanical EGR systems, and in some cases, no EGR at all. Nonetheless, the use of EGR remains a very important tool in reducing engine-out NO_x emissions, whether mechanical or electronic.

Multiple Valves and Variable-Valve Timing

Conventional engines have two valves per cylinder, one for intake of the air-fuel mixture and the other for exhaust of the combustion products. The duration and lift (distance the valve head is pushed away from its seat) of valve openings is constant regardless of engine speed. As engine speed increases, the aerodynamic resistance to pumping air in and out of the cylinder for intake and exhaust also increases. By doubling the number of intake and exhaust valves, pumping losses are reduced, improving the volumetric efficiency and useful power output.

In addition to gains in breathing, the multiple-valve (typically 4-valve) design allows the spark plug to be positioned closer to the center of the combustion chamber (as discussed above) which decreases the distance the flame must travel inside the chamber. In addition, the two

¹ Some manufacturers have stated that EGR impacts the ability to control net air-fuel ratios tightly due to dynamic changes in exhaust back pressure and temperature, and that the advantages of increasing EGR flow rates are lost partly in losses in air-fuel ratio control even with electronic control of EGR. Higher EGR flow rates can be tolerated by modern engines with more advanced combustion chambers, but EGR cooling may be necessary to achieve higher EGR flow rates within acceptable detonation limits without significant loss of air-fuel control.

streams of incoming gas can be used to achieve greater mixing of air and fuel, further increasing combustion efficiency which lowers engine-out HC emissions.

Even greater improvements to combustion efficiency can be realized by using valve timing and lift control to take advantage of the 4-valve configuration. Conventional engines utilize fixed-valve timing and lift across all engine speeds. Typically the valve timing is set at a level that is a compromise between low speed torque and high engine speed horsepower. At light engine loads it would be desirable to close the intake valve earlier to reduce pumping losses. Variable valve timing can enhance both low speed torque and high speed horsepower with no necessary compromise between the two. Variable valve timing can allow for increased swirl and intake charge velocity, especially during low load operating conditions where sufficient swirl and turbulence tend to be lacking. By providing a strong swirl formation in the combustion chamber, the air-fuel mixture can mix sufficiently, resulting in a faster, more complete combustion, even under lean air-fuel conditions, thereby reducing emissions. Variable valve technology by itself may have somewhat limited effect on reducing emissions. Several vehicle manufacturers estimated emission reductions of 3 percent-10 percent for both NMHC and NO_x, but reductions could be increased when variable valve timing is combined with optimized spark plug location and additional EGR.

Multi-valve engines already exist in numerous federal and California certified vehicles and are projected by ARB to become even more common. ARB also projects that in order to meet LEV II and ULEV II standards, more vehicles will have to make improvements to the induction system, including the use of variable valve timing.

Leak-Free Exhaust System

Leaks in the exhaust system can result in increased emissions, but not necessarily from emissions escaping from the exhaust leak to the atmosphere. With an exhaust system leak, ambient air is typically sucked into the exhaust system by the pressure difference created by the flowing exhaust gases inside the exhaust pipe. The air that is sucked into the exhaust system is unmetered and, therefore, unaccounted for in the fuel system's closed-loop feedback control. The excess air in the exhaust causes the computer to increase fuel to the engine, resulting in erratic and/or overly rich fuel control. This results in increased emission levels and potentially poor driveability. In addition, an air leak can cause an oxidation environment to exist in a three-way catalyst at low speeds that would hamper reduction of NO_x and lead to increased NO_x emissions.

Some vehicles currently use leak-free exhaust systems today. These systems consist of an improved exhaust manifold/exhaust pipe interface plus a corrosion-free flexible coupling inserted between the exhaust manifold flange and the catalyst to reduce stress and the tendency for leakage to occur at the joint. In addition, improvements to the welding process for catalytic converter canning could ensure less air leakage into the converter and further reduce emissions.

ii. Improvements in Air-Fuel Ratio Control

Modern three-way catalysts require the air-fuel ratio (A/F) to be as close to stoichiometry (the amount of air and fuel just sufficient for nearly complete combustion) as possible. This is because three-way catalysts simultaneously oxidize HC and CO, and reduce NO_x. Since HC and CO are oxidized during A/F operation slightly lean of stoichiometry, while NO_x is reduced during operation slightly rich of stoichiometry, there exists a very small A/F window of operation around stoichiometry where catalyst conversion efficiency is maximized for all three pollutants (i.e., less than 1 percent deviation in A/F or roughly ± 0.15). Contemporary vehicles have been able to maintain stoichiometry, or very close to it, by using closed-loop feedback fuel control systems. At the heart of these systems has been a single heated exhaust gas oxygen (HEGO) sensor. The HEGO sensor continuously switches between rich and lean readings. By maintaining an equal number of rich readings with lean readings over a given period, and by limiting the degree to which the exhaust is rich or lean at any point in time, the fuel control system is able to maintain stoichiometry. While this fuel control system is capable of maintaining the A/F with the required accuracy under steady-state operating conditions, the system accuracy is challenged during transient operation where rapidly changing throttle conditions occur. Also, as the sensor ages, its accuracy decreases.

Dual Oxygen Sensors

Many vehicle manufacturers have placed a second HEGO sensor(s) downstream of one or more catalysts in the exhaust system as a method for monitoring the catalyst effectiveness of the federally and California mandated on-board diagnostic (OBD II) system. In addition to monitoring the effectiveness of the catalyst, the downstream sensors can also be used to monitor the primary control sensor and adjust for deterioration, thereby maintaining precise A/F control at higher mileages. Should the front primary HEGO sensor, which operates in a higher temperature environment, begin to exhibit slow response or drift from its calibration point, the secondary downstream sensor can be relied upon for modifying the fuel system controls to compensate for the aging effects. By placing the second sensor further downstream from the hot engine exhaust, where it is also less susceptible to poisoning, the rear sensor is less susceptible to aging over the life of the vehicle. As a result, the use of a dual oxygen sensor fuel control system can ensure more robust and precise fuel control, resulting in lower emissions.

Currently, all vehicle manufacturers use a dual oxygen sensor system for monitoring the catalyst as part of the OBD II system. As discussed above, most manufacturers also utilize the secondary HEGO sensor for trim (i.e., adjustments to) of the fuel control system. It is anticipated that all manufacturers will soon use the secondary sensor for fuel trim.

Universal Oxygen Sensors

The universal exhaust gas oxygen (UEGO) sensor, also called a "linear oxygen sensor", could replace conventional HEGO sensors. Conventional HEGO sensors only determine if an engine's A/F is richer or leaner than stoichiometric, providing no indication of the exact level of the A/F. In contrast, UEGO's are capable of recognizing both the direction and magnitude of A/F transients since the voltage output of the UEGO is "proportional" with changing A/F (i.e., each voltage value corresponds to a certain A/F). Therefore, proportional A/F control is possible with the use of UEGO sensors, facilitating faster response of the fuel feedback control system and tighter control of A/F.

Although some manufacturers are currently using UEGO sensors, discussions with various manufacturers suggest that some manufacturers are of mixed opinion as to the future applicability of UEGO sensors. Because of their high cost, manufacturers claim that it may be cheaper to improve HEGO technology rather than utilize UEGO sensors. An example of this is the use of a "planar" design for HEGO sensors. Planar HEGO sensors (also known as "fast light-off" HEGO sensors) have a thimble design that is considerably lighter than conventional designs. The main benefits are shorter heat-up time and faster sensor response.

Individual Cylinder A/F Control

Another method for tightening fuel control is to control the A/F in each individual cylinder. Current fuel control systems control the A/F for the entire engine or a bank of cylinders. By controlling A/F for the entire engine or a bank of cylinders, any necessary adjustments made to fuel delivery for the engine are applied to all cylinders simultaneously, regardless of whether all cylinders need the adjustment. For example, there is usually some deviation in A/F between cylinders. If a particular cylinder is rich, but the "bulk" A/F indication for the engine is lean, the fuel control system will simultaneously increase the amount of fuel delivered to all of the cylinders, including the rich cylinder. Thus, the rich cylinder becomes even richer having a potentially negative effect on the net A/F.

Individual cylinder A/F control helps diminish variation among individual cylinders. This is accomplished by modeling the behavior of the exhaust gases in the exhaust manifold and using sophisticated software algorithms to predict individual cylinder A/F. Individual cylinder A/F control requires use of an UEGO sensor in lieu of the traditional HEGO sensor, and requires a more powerful engine control computer.

Adaptive Fuel Control Systems

The fuel control systems of virtually all current vehicles incorporate a feature known as "adaptive memory" or "adaptive block learn." Adaptive fuel control systems automatically adjust the amount of fuel delivered to compensate for component tolerances, component wear, varying environmental conditions, varying fuel compositions, etc., to more closely maintain proper fuel

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control under various operating conditions.

For most fuel control systems in use today, the adaption process affects only steady-state operation conditions (i.e., constant or slowly changing throttle conditions). Because transient operating conditions have always provided a challenge to maintaining precise fuel control, the use of adaptive fuel control for transient operation would be extremely valuable. Accurate fuel control during transient driving conditions has traditionally been difficult because of inaccuracies in predicting the air and fuel flow under rapidly changing throttle conditions. Air and fuel dynamics within the intake manifold (fuel evaporation and air flow behavior), and the time delay between measurement of air flow and the injection of the calculated fuel mass, result in temporarily lean A/F during transient operation. Variation in fuel properties, particularly distillation characteristics, also increases the difficulty in predicting A/F during transients. These can all lead to poor driveability and an increase in NO_x emissions.

Electronic Throttle Control Systems

As mentioned above, the time delay between the air mass measurement and the calculated fuel delivery presents one of the primary difficulties in maintaining accurate fuel control and good driveability during transient driving conditions. With the conventional mechanical throttle system (a metal linkage connected from the accelerator pedal to the throttle blade in the throttle body), quick throttle openings can result in a lean A/F spike in the combustion chamber. Although algorithms can be developed to model air and fuel flow dynamics to compensate for these time delay effects, the use of an electronic throttle control system, known as “drive-by-wire” or “throttle-by-wire,” may better synchronize the air and fuel flow to achieve proper fueling during transients (e.g., the driver moves the throttle, but the fuel delivery is momentarily delayed to match the inertial lag of the increased airflow).

While this technology is currently used on several vehicle models, it is considered expensive and those vehicles equipped with the feature are expensive, higher end vehicles. Because of its high cost, it is not anticipated that drive-by-wire technology will become commonplace in the near future.

iii. Improvements in Fuel Atomization

In addition to maintaining a stoichiometric A/F ratio, it is also important that a homogeneous air-fuel mixture be delivered at the proper time and that the mixture is finely atomized to provide the best combustion characteristics and lowest emissions. Poorly prepared air-fuel mixtures, especially after a cold start and during the warm-up phase of the engine, result in significantly higher emissions of unburned HC since combustion of the mixture is less complete. By providing better fuel atomization, more efficient combustion can be attained, which should aid in improving fuel economy and reducing emissions. Sequential multi-point fuel injection and air-assisted fuel injectors are examples of the most promising technologies

available for improving fuel atomization.

Sequential Multi-Point

Typically, conventional multi-point fuel injection systems inject fuel into the intake manifold by injector pairs. This means that rather than injecting fuel into each individual cylinder, a pair of injectors (or even a whole bank of injectors) fires simultaneously, sending fuel into several cylinders. Since only one of the cylinders is actually ready for fuel at the moment of injection, the other cylinder(s) gets too much or too little fuel. With this less than optimum fuel injection timing, fuel puddling and intake manifold wall wetting can occur, both of which can hinder complete combustion. Sequential injection, on the other hand, delivers a more precise amount of fuel that is required by each cylinder to each cylinder at the appropriate time. Because of the emission reductions and other performance benefits “timed” fuel injection offers, sequential fuel injection systems are very common on today’s vehicles and are expected to be incorporated in all vehicles soon.

Air-Assisted Fuel Injectors

Another method to further homogenize the air-fuel mixture is through the use of air-assisted fuel injection. By injecting high pressure air into the fuel injector, and subsequently, the fuel spray, greater atomization of the fuel droplets can occur. Since achieving good fuel atomization is difficult when the air flow into the engine is low, air-assisted fuel injection can be particularly beneficial in reducing emissions at low engine speeds. In addition, industry studies have shown that the short burst of additional fuel needed for responsive, smooth transient maneuvers can be reduced significantly with air-assisted fuel injection due to a decrease in wall wetting in the intake manifold.

iv. Improvements to Exhaust Aftertreatment Systems

Over the last five years or so, there have been tremendous advancements in exhaust aftertreatment systems. Catalyst manufacturers are progressively moving to palladium as the main precious metal in automotive catalyst applications. Improvements to catalyst thermal stability and washcoat technologies, the design of higher cell densities, and the use of two-layer washcoat applications are just some of the advancements made to catalyst technology. There has also been much development in HC and NO_x absorber technology. The advancements to exhaust aftertreatment systems are probably the single most important area of emission control development.

Catalysts

As previously mentioned, significant changes in catalyst formulation, size and design

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have been made in recent years and additional advances in these areas are still possible. Palladium (Pd) is likely to continue as the precious metal of choice for close-coupled applications and will start to see more use in underfloor applications. Some manufacturers, for example, have suggested that they will use Pd/Rh in lieu of tri-metal or conventional Pt/Rh catalysts for underfloor applications. Palladium catalysts, however, are less resistant to poisoning by oil-and fuel-based additives than conventional platinum/rhodium (Pt/Rh) catalysts. Based on current certification trends and information from vehicle manufacturers and catalyst suppliers, it is expected that Pd-only and Pd/Rh catalysts will be used in the close-coupled locations while conventional Pd/Rh, Pt/Rh or tri-metal (Pd/Pt/Rh) catalysts will continue to be used in underfloor applications. As palladium technology continues to improve, it may be possible for a single close-coupled catalyst to replace both catalysts. In fact, at least one vehicle manufacturer currently uses a single Pd-only catalyst for one of their models. According to MECA, new Pd-based catalysts are now capable of withstanding exposure to temperatures as high as 1100°C and, as a result, can be moved very close to the exhaust manifold to enhance catalyst light-off performance.

In addition to an increased reliance on Pd, catalyst manufacturers have developed “multi-layered” washcoat technologies. Automotive catalysts consist of a cylindrical or oval shaped substrate, typically made of ceramic or metal. The substrate is made up of hundreds of very small, but long cells configured in a shape similar to a honey-comb. The substrate is coated with a substance containing precious metals, rare earth metals, and base-metal oxides, that is known as the catalyst washcoat. Typical washcoat formulations consist of precious metals which either oxidize or reduce pollutants, base-metal oxides, such as alumina, which provide the surface area support for the precious metals to adhere to, and base components (rare earth metals) such as lanthanum, ceria, and zirconia, which act as promoters and stabilizers, and encourage storage and reduction of oxygen. Conventional catalysts have a single layer of washcoat and precious metals applied to the catalyst substrate. More advanced catalysts use multi-layered washcoats with two or more layers of different combinations of washcoat and precious metals. The washcoat can be applied to the substrate such that one layer can be applied on top of another. The use of multi-layered washcoat technology allows precious metals that have adverse reactions together to be separated such that catalyst durability and emission reduction performance are significantly enhanced. For example, Pd and Rh can have adverse reactions when combined together in a single washcoat formulation. A multi-layer washcoat architecture that uses Pd and Rh could have the Pd on the bottom layer and the Rh on the top layer. Rh is particularly used at reducing NO_x. It is generally preferable to reduce NO_x in the top layer while CO and HC are still present and then oxidize CO and HC in the bottom layer. Figure IV-1 illustrates the impact coating architecture (multi-layered washcoat technology) can have on emission performance.

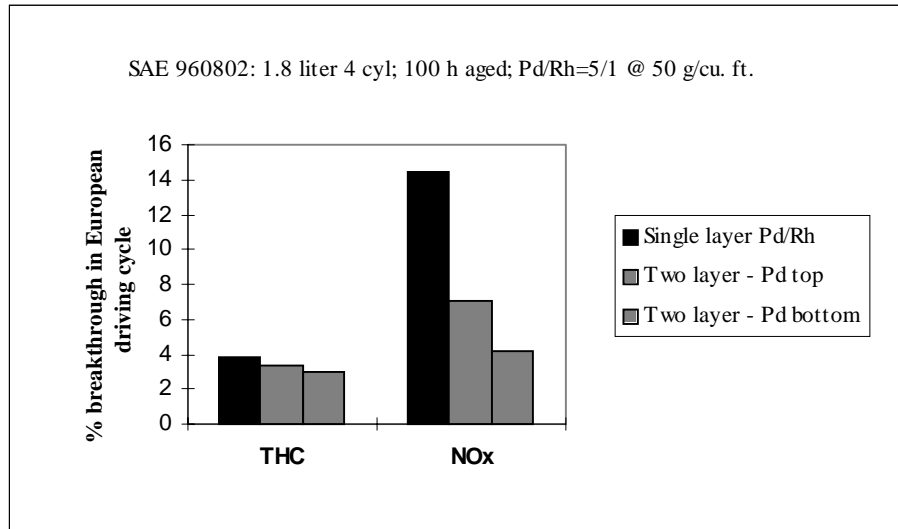


Figure IV-1. Impact of Coating Architecture on HC and NOx Emissions.

Manufacturers have also been developing catalysts with substrates which utilize thinner walls in order to design higher cell density, low thermal mass catalysts for close-coupled applications (improves mass transfer at high engine loads and increases catalyst surface area as well as speeding up light-off during cold starts). The greater the number of cells there are, the more surface area that exists for washcoat components and precious metals to adhere to, resulting in more precious metal sites available for oxidizing and reducing pollutants. Cell densities of 600 cells per square inch (cps) have already been commercialized, and research on 900 and 1200 cps catalysts has been progressing. Typical cell densities for conventional catalysts are 400 cps.

We have projected that in order to meet the Tier 2 emission standards catalyst volumes will increase. Current California LEV and ULEV passenger car catalyst volume to engine displacement ratios are approximately 0.7 to over 1.0 while many light and medium duty trucks only have ratios of 0.6 or less. We believe that in order to comply with Tier 2 standards, most vehicles will likely need catalyst volumes equal to the displacement of the engine, or in some cases, even greater. As mentioned above, higher cell density substrates effectively provide more surface area for pollutant conversion, therefore catalyst volumes may not need to be increased as significantly if higher cell density substrates are used.

We have also projected that some level of increased catalyst loading will be necessary to meet Tier 2 standards. Typical catalyst loadings for current LEVs and ULEVs range from 50 g/cu ft to 300 g/cu ft. We believe that, based on input from catalyst suppliers and vehicle manufacturers, depending on the vehicle, catalysts meeting Tier 2 standards will need loadings in the 100 - 250 g/cu ft range. However, catalyst suppliers have also indicated to us that they and vehicle manufacturers are constantly working on ways to reduce the amount of precious metal loading (a process they refer to as “thrifting”). Thrifting is achieved in several ways. One of the

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most common is matching the catalyst to the attributes of the vehicle. By working in unison, vehicle manufacturers and catalyst suppliers are able to thrift or reduce the amount of precious metal used in a given application by attempting to optimize the vehicle fuel control strategy, exhaust mass flow rate, and exhaust temperature with various catalyst parameters, such as catalyst location, substrate design, cell density, oxygen storage capability, and precious metal and base metal dispersion, to name a few. Other methods of thrift are the constant improvements being made to washcoat architecture - that is, constant improvement to the materials used in the washcoat formulation so that the precious metals and other components better adhere to the substrate surface. Finally, improvements to washcoat application processes can also significantly improve catalyst performance while allowing thrift of precious metals. Improvements to processes consist of advancements to the process used to coat the substrate with washcoat materials - allowing precious metals, base metals, and ceria to be better dispersed. Better dispersion means that rather than relatively large "clumps" of precious metals unevenly dispersed throughout the catalyst surface, many smaller precious metal sites are dispersed uniformly throughout the catalyst surface increasing the chance for pollutants to come into contact with the precious metal and react into a harmless emission. Therefore, as thrift continues, it is possible that precious metal loading may actually decrease rather than increase.

The largest source of HC emissions continues to be cold start operation where the combination of rich A/F operation and the ineffectiveness of a still relatively cool catalyst results in excess HC emissions. One of the most effective strategies for controlling cold start HC emissions is to reduce the time it takes to increase the operating temperature of the catalyst immediately following engine start-up. The effectiveness or efficiency of the catalyst increases as the catalyst temperature increases. One common strategy is to move the catalyst closer to the exhaust manifold where the exhaust temperature is greater (e.g., a close-coupled catalyst). In addition to locating the catalyst closer to the engine, retarding the spark timing and increasing idle speed are other possible approaches. Retarding spark timing causes combustion to occur later in the power stroke, allowing more heat to escape into the exhaust manifold during the exhaust stroke. Increased idle speed leads to a greater amount of combustion per unit time, providing a greater quantity of heat for heating the exhaust manifold, headpipe, and catalyst.

Adsorbers/Traps

Other potential exhaust aftertreatment systems that are used in conjunction with a catalyst or catalysts, are the HC and NO_x adsorbers or traps. Hydrocarbon adsorbers are designed to trap HC while the catalyst is cold and unable to sufficiently convert the HC. They accomplish this by utilizing an adsorbing material which holds onto the HC. Once the catalyst is warmed up, the trapped HC are automatically released from the adsorption material and are converted by the fully functioning downstream three-way catalyst. There are three principal methods for incorporating an adsorber into the exhaust system. The first is to coat the adsorber directly on the catalyst substrate. The advantage is that there are no changes to the exhaust system required, but

the desorption process cannot be easily controlled and usually occurs before the catalyst has reached light-off temperature. The second method locates the adsorber in another exhaust pipe parallel with the main exhaust pipe, but in front of the catalyst and includes a series of valves that route the exhaust through the adsorber in the first few seconds after cold start, switching exhaust flow through the catalyst thereafter. Under this system, mechanisms to purge the adsorber are also required. The third method places the trap at the end of the exhaust system, in another exhaust pipe parallel to the muffler, because of the low thermal tolerance of adsorber material. Again a purging mechanism is required to purge the adsorbed HC back into the catalyst, but adsorber overheating is avoided.

One manufacturer who incorporates a zeolite HC adsorber in its California SULEV vehicle found that an electrically heated catalyst was necessary after the adsorber because the zeolite acts as a heat sink and nearly negates the cold start advantage of the HC adsorber.

NO_x adsorbers are also being developed, but according to MECA, are generally recognized as a control for NO_x resulting from reduced EGR. They are typically used for lean-burn applications and are not applicable to engines that attempt to maintain stoichiometry all the time.

Secondary Air Injection

Secondary injection of air into exhaust ports after cold start (e.g., the first 40-60 seconds) when the engine is operating rich, coupled with spark retard, can promote combustion of unburned HC and CO in the exhaust manifold and increase the warm-up rate of the catalyst. By means of an electrical pump, secondary air is injected into the exhaust system, preferably in close proximity of the exhaust valve. Together with the oxygen of the secondary air and the hot exhaust components of HC and CO, oxidation ahead of the catalyst can bring about an efficient increase in the exhaust temperature which helps the catalyst to heat up quicker. The exothermic reaction that occurs is dependent on several parameters (secondary air mass, location of secondary air injection, engine A/F ratio, engine air mass, ignition timing, manifold and headpipe construction, etc.), and ensuring reproducibility demands detailed individual application for each vehicle or engine design.

Insulated or Dual Wall Exhaust System

Insulating the exhaust system is another method of furnishing heat to the catalyst to decrease light-off time. Similar to close-coupled catalysts, the principle behind insulating the exhaust system is to conserve heat generated in the engine to aid the catalyst warm-up. Through the use of laminated thin-wall exhaust pipes, less heat will be lost in the exhaust system, enabling quicker catalyst light-off.

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v. Improvements in Engine Calibration Techniques

Of all the technologies discussed above, one of the most important emission control strategies is not hardware-related. Rather, it is software related and, more specifically, involves the algorithms and calibrations contained within the software that are used in the power-train control module (PCM) which control how the various engine and emission control components and systems operate. Advancements in software along with refinements to existing algorithms and calibrations can have a major impact in reducing emissions. Confidential discussions between manufacturers and EPA have suggested that manufacturers believe emissions can be further reduced by improving and updating their calibration techniques. As computer technology and software continues to advance, so does the ability of the automotive engineer to use these advancements in ways to better optimize the emission control systems. For example, as processors become faster, it is possible to perform calculations more quickly, thus allowing for faster response times for controlling engine parameters, such as fuel rate and spark timing. As the PCM becomes more powerful with greater memory capability, algorithms can become more sophisticated. Manufacturers have found that as computer processors, engine control sensors and actuators, and computer software become more advanced, and, in conjunction with their growing experience with developing calibrations, as time passes, their calibration skills will continue to become more refined and robust, resulting in even lower emissions.

Manufacturers have suggested to EPA that perhaps the single most effective method for controlling NO_x emissions will be tighter A/F control which could be accomplished with advancements in calibration techniques without necessarily having to use advanced technologies, such as UEGO sensors. Manufacturers have found ways to improve calibration strategies such that meeting federal cold CO requirements, as well as, complying with LEV standards, have not required the use of advanced hardware, such as EHCs or adsorbers.

Since emission control calibrations are typically confidential, it is difficult to predict what advancements will occur in the future, but it is clear that improved calibration techniques and strategies are a very important and viable method for further reducing emissions.

b. Data Supporting Tier 2 Technical Feasibility

Automobile manufacturers generally design vehicles to meet emission targets which are 50-70 percent of the emission standards after the catalytic converters have been thermally aged to the equivalent of both the intermediate useful life (50,000 miles) and full useful life (120,000 miles). The manufacturer desires this 30-50 percent safety margin in order to reduce the probability that in-use vehicles will exceed the standard to an acceptable level. Thus, the emission design targets for Tier 2 standards at intermediate useful would be approximately 0.035 to 0.050 g/mi NMOG and 0.025 to 0.035 g/mi NO_x. At full useful life, the design targets for the Tier 2 standards would be approximately 0.045-0.063 g/mi NMOG and 0.035-0.050 g/mi NO_x at

full useful life.

With this in mind, we will present data from several sources that establish our Tier 2 standards to be feasible. The data ranges from certification emission levels to feasibility evaluation programs undertaken in the last year by EPA, ARB and MECA. Even though the ARB and MECA programs were directed towards the LEV II program, the data and information resulting from these programs are useful to EPA in establishing feasibility of Tier 2 emission standards since our Tier 2 standards are the same as the LEV II standards. We will also present the results of an EPA test program that demonstrates the feasibility of the Tier 2 emissions standards for the largest sport utility vehicles and pickup trucks regulated under this final rule.

i. Certification Emission Levels

Manufacturers report certification results for engine families. Those engine families are used in a variety of vehicle models and configurations. Manufacturers are required to report certification test results for at least two vehicle configurations and often report results for five or six or more models or configurations within an engine family. Manufacturers, for example, will report certification test results for both automatic and manual transmission versions of a vehicle. Table IV-2 below indicates the number of 1999 model year engine families with at least one vehicle configuration at or below full-life NO_x levels of 0.04, 0.07, and 0.1 g/mile. Of those at or below 0.04 and 0.07 g/mile NO_x, 16 and 35, respectively, also have HC levels below 0.09 g/mile. There are approximately 400 engine families total.

Table IV-2. Number of 1999 Model Year Engine Families with One or More Engine/Vehicle Configurations with Low Full-life NO_x Levels

<i>NO_x level</i>	<i>Vehicles Below 6,000 pounds (LDVs, LDT1s, LDT2s)</i>	<i>Vehicles Above 6,000 pounds (LDT3s, LDT4s)</i>
≤ 0.04	20	2
≤ 0.07	45	3
≤ 0.1	150	11

Table IV-3 provides a listing of engine families with one or more vehicle configurations at or below 0.07 g/mile NO_x. The table also provides the HC certification levels for those configurations. Where a range is shown, there is more than one configuration within the engine family with full-life NO_x certification levels at or below 0.07. The same vehicle models appear in the table more than once because multiple engine families are often certified for the same vehicle models. EPA assembled this list by reviewing 1999 model year certification data for

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engine families certified to nationwide Tier 1 standards, NLEV program standards, and the California program standards.

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**Table IV-3. 1999 MY Engine Families with One or More Vehicle Configurations
with Full-life NOx Certification Levels at or below 0.07 g/mile NOx**

<i>Manufacturer</i>	<i>Models</i>	<i>NOx level</i>	<i>HC level</i>	<i>Standard</i>
LDVs (passenger cars)				
Hyundai	Elantra Wagon, Tiburon	0.01 - 0.02	0.05	LEV
Ford	Contour, Mystique, Cougar	0.02 - 0.05	0.12 - 0.17	Tier 1
Ford	Contour, Mystique, Cougar	0.02*	0.12	Tier 1
Volkswagon, Audi	Passat, Passat wagon A4	0.03 - 0.07*	0.06 - 0.07	TLEV
Volvo	V70, S70	0.03	0.06 - 0.08	TLEV
Volvo	S70, V70, C70	0.03 - 0.04	0.05 - 0.07	LEV
Hyundai	Elantra, Tiburon	0.03 - 0.04* ⁺	0.04 - 0.06	Tier 1
Daimler Chrysler	Cirrus, Stratus, Breeze	0.04* ⁺	0.06	LEV
Mitsubishi	Diamante	0.04* ⁺	0.05	LEV
Mitsubishi	Gallant, Mirage	0.04 ⁺	0.03	LEV
Suzuki	Metro	0.04	0.03	TLEV
Ford	Mustang	0.04	0.17 - 0.21	Tier 1
Ford	Contour, Mystique, Cougar	0.04 - 0.05	0.07 - 0.08	TLEV
Daimler Chrysler	S320	0.04 ⁺	0.07	Tier 1
Hyundai	Sonata	0.04 - 0.06*	0.07	TLEV
Volkswagon	Jetta, Golf, Cabriolet	0.04 - 0.06	0.04 - 0.07	TLEV
Nissan	Altima	0.05	0.03	LEV
Ford	Sable, Taurus	0.05 - 0.06	0.13 - 0.14	Tier 1
Ford	Mustang	0.05 - 0.06	0.07	TLEV
Ford	Contour, Mystique, Cougar	0.06	0.07	Tier 1
Daimler Chrysler	E430, SL500	0.06 - 0.07	0.02	LEV
Daimler Chrysler	SL600	0.06	0.12	Tier 1
Hyundai	Accent	0.06*	0.08 - 0.1	TLEV
Hyundai	Sonata	0.06*	0.04 - 0.05	TLEV

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Volkswagon	New Beetle, New Golf, New Jetta	0.06*	0.06	LEV
Mazda	MX-5 Miata	0.07	0.07	TLEV
Mitsubishi	Mirage	0.07	0.05	LEV
Volvo	S80	0.06 - 0.07*	0.07 - 0.08	TLEV
Volvo	S80	0.04 - 0.05	0.11	TLEV
Daimler Chrysler	C230 Kompressor	0.07	0.03	TLEV
Honda	Accord	0.07*	0.04 - 0.05	LEV
Honda	Civic HX	0.07*	0.09	TLEV
Honda	Civic	0.07*	0.07 - 0.08	TLEV
Infiniti	Q45	0.07*	0.11	Tier 1
LDT 1				
Daimler Chrysler	Jeep Cherokee 2WD, 4WD	0.03* ⁺	0.06	Tier 1
Ford	Ranger	0.04 - 0.07	0.09 - 0.18	Tier 1
Mazda	B2500, B3000	0.04 - 0.06	0.08 - 0.13	Tier 1
Ford	Ranger	0.05*	0.11	Tier 1
LDT2				
Ford	Explorer	0.03 - 0.04	0.07 - 0.10	Tier1
Ford, Mazda	Ranger, B3000	0.04 - 0.07	0.12 - 0.15	Tier 1
Ford	F-150	0.05*	0.08 - 0.10	Tier 1
Mazda	B3000	0.05*	0.06 - 0.07	Tier 1
Ford, Mazda	Ranger, B3000	0.05 - 0.07	0.07 - 0.12	Tier 1
Daimler Chrysler	Caravan, Voyager	0.07		LEV
Nissan	Frontier	0.07*	0.07	LEV
LDT3				
Ford	F-150	0.04 - 0.06	0.07 - 0.08	Tier 1
Ford	F-150	0.05 - 0.06	0.11 - 0.12	Tier 1
LDT4				

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Ford	Expedition, Navigator, F-250	0.04*	0.16 - 0.17	Tier 1
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* Other model configurations have NO_x certification levels above 0.07 g/mile

+ The official NO_x certification result reported was 0 for these vehicles due to rounding. The values shown are the unrounded results.

Table IV-4 provides a listing of 2000 model year engine families with one or more vehicle configurations at or below 0.07 g/mile NO_x. The table also provides the HC certification levels for those configurations. As for the 1999 data, where a range is shown, there is more than one configuration within the engine family with full-life NO_x certification levels at or below 0.07. The same vehicle models appear in the table more than once because multiple engine families are often certified for the same vehicle models. We assembled this list by reviewing 2000 model year certification data for engine families certified to nationwide Tier 1 standards, NLEV program standards, and the California program standards. At the time this document was published, approximately 90 percent of the 2000 model year certification data had been submitted.

Table IV-4. 2000 MY Engine Families with One or More Vehicle Configurations with Full-life NO_x Certification Levels at or below 0.07 g/mile NO_x

<i>Manufacturer</i>	<i>Models</i>	<i>NO_x level</i>	<i>HC level</i>	<i>Standard</i>
LDVs (passenger cars)				
Hyundai	Tiburon, Elantra	0.01 - 0.02 ⁺	0.05	LEV
Daimler Chrysler	Neon	0.01	0.05	ULEV
Ford	Mystique, Contour	0.01 - 0.04*	0.03 - 0.05	TLEV
Volvo	S80	0.01	0.05	LEV
Ford	Mystique	0.02 - 0.03 ⁺	0.03 - 0.04	Tier 1
Daimler Chrysler	Neon	0.02	0.04	ULEV
Mitsubishi	Eclipse, Gallant	0.02* ⁺	0.02 - 0.04	LEV
Mitsubishi	Mirage	0.02 - 0.03* ⁺	0.03 - 0.04	LEV
Daewoo	Lanos	0.02 - 0.07	0.06 - 0.07	LEV
SAAB	9-5	0.03	0.03	LEV
Daimler Chrysler	Stratus	0.03	0.06	LEV
Hyundai	Tiburon, Elantra	0.03 - 0.04* ⁺	0.04 - 0.05	Tier 1
Ford	LS	0.03 - 0.05	0.06 - 0.07	LEV

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Volvo	S70, V70	0.03*	0.03 - 0.04	LEV
Toyota	Avalon, Lexus ES300	0.03 - 0.06	0.05	LEV
Jaguar	X200	0.03 - 0.05*	0.05 - 0.07	TLEV
Mazda	Protege	0.04 ⁺	0.03	LEV
Honda	Accord	0.04 - 0.06	0.04 - 0.05	LEV
Volvo	S80	0.04 - 0.06*	0.09	TLEV
Daimler Chrysler	SLK230 Kompressor, C230 Kompressor	0.04 - 0.05	0.04 - 0.05	TLEV
GM	Metro	0.04 ⁺	0.03	TLEV
GM	Park Avenue	0.04 ⁺	0.04	LEV
Honda	Accord	0.04 - 0.06	0.05 - 0.06	LEV
Mazda	Protege	0.04	0.03	LEV
Volvo	S40	0.05 - 0.06*	0.06 - 0.07	LEV
Hyundai	Sonata	0.05	0.05	TLEV
Daimler Chrysler	ML320	0.05*	0.04 - 0.05	Tier 1
Nissan	Infiniti G20	0.06*	0.04	LEV
Kia	Sephia	0.06 - 0.07*	0.04 - 0.08	LEV
Honda	Accord	0.06 - 0.07*	0.06	LEV
Infiniti	I30	0.06	0.05	LEV
Ford	Contour, Cougar	0.06*	0.16	Tier 1
Toyota	Lexus GS300/GS400	0.06*	0.05 - 0.06	LEV
Volkswagen	Jetta	0.06*	0.06	LEV
Daewoo	Nubira, Lanos	0.06*	0.08	TLEV
Honda	Insight	0.06*	0.04	ULEV/LEV
Daewoo	Leganza, Nubira	0.07*	0.05 - 0.07	LEV
Honda	Accord	0.07*	0.03	ULEV
Daimler Chrysler	E430, S500	0.07*	0.02	LEV
BMW	X5	0.07	0.04	LEV
Nissan	Altima	0.07	0.06	LEV

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SAAB	9-5	0.07	0.02 - 0.03	LEV
Hyundai	Accent/Brio	0.07*	0.03	LEV
LDT 1				
Toyota	Tacoma	0.01 - 0.02	0.05 - 0.07	LEV
Kia	Sportage	0.02 - 0.05	0.04 - 0.06	LEV
Ford	Ranger Pickup	0.04 - 0.07	0.09 - 0.18	Tier 1
Mazda	B2000	0.06*	0.05	Tier 1
Daimler Chrysler	Dakota Pickup	0.07	0.08	TLEV
LDT2				
Ford	F150 Pickup	0.03*	0.13 - 0.16	Tier 1
Ford	Ranger Pickup	0.04*	0.13 - 0.15	Tier 1
Mazda	B3000	0.04 - 0.05*	0.06 - 0.10	Tier 1
GM	Montana	0.05 ⁺	0.05 - 0.06	LEV
Daimler Chrysler	Grand Cherokee	0.05	0.10 - 0.11	LEV
Daimler Chrysler	Caravan	0.06	0.09	LEV
LDT3				
Ford	F150 Pickup	0.03 - 0.04	0.16 - 0.20	Tier 1
Daimler Chrysler	Durango	0.05	0.08	ULEV
Ford	F150 Pickup	0.05*	0.14 - 0.16	Tier 1
Daimler Chrysler	ML55	0.06 - 0.07	0.04 - 0.05	LEV
Land Rover	Range Rover, Discovery	0.07*	0.09 - 0.17	Tier 1
LDT4				
Ford	F250 Pickup	0.04 - 0.05	0.13 - 0.21	Tier 1

* Other model configurations have NO_x certification levels above 0.07 g/mile

+ The official NO_x certification result reported was 0 for these vehicles due to rounding. The values shown are the unrounded levels.

A review of the Tables above show that most of the engine families with configurations certified at 0.07 g/mile NO_x or less are passenger cars and lighter weight LDTs . This is understandable since all LDT classes except LDT1 have emission standards considerably higher than LDVs. Thus, to this point, there has been no motivation for vehicle manufacturers to design

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and produce light-duty trucks with emission control systems on par with light-duty vehicle systems. Even so, there are several light-duty trucks with certification levels at or very close to the Tier 2 requirements.

ii. Industry Sulfur Test Program

The Coordinating Research Council (CRC), automobile manufacturers and the American Petroleum Institute (API) all tested a number of vehicles capable of complying with the California LEV or ULEV standards. The primary purpose of these test programs was to estimate how higher fuel sulfur levels affected emissions. However, the test results with low sulfur fuel (i.e., 30-40 ppm sulfur) provide an indication of the emission control potential of these vehicles. Of the 20 unique vehicle models tested in these programs, four models met both of the Tier 2 NMOG and NO_x design targets mentioned above. An additional three models had NMOG levels below the design targets and NO_x levels above the design targets, but below the NO_x standard. All of these low emitting models were LDVs with 100K catalyst systems.

iii. MECA Test Program

The Manufacturers of Emission Controls Association (MECA) sponsored vehicle emission testing at the Southwest Research Institute (SwRI)¹ for the purpose of demonstrating the performance of advanced emission control systems in meeting California LEV II and our Tier 2 light-duty vehicle standards. SwRI took two LDVs (a 1997 3.8L Buick LeSabre and a 1997 4.6L Ford Crown Vic) and one LDT2 (3.4L Toyota T100) certified to the federal Tier 1 standards and replaced the original catalytic converters with more advanced catalytic converters provided by MECA members. The catalysts were thermally aged to the equivalent of 50,000 miles of in-use operation. SwRI then attempted to optimize the emission performance by modifying the existing secondary air and exhaust gas recirculation (EGR) strategies. This was accomplished by using a computer controlled intercept system (Emissions Reduction Intercept and Control system or ERIC). This computer intercept methodology was used to recognize and modify only driving modes associated with high tailpipe emission modes, thereby minimizing the level of modifications to the base vehicle control system. The control tuning approach developed for each vehicle was unique to the individual vehicle. The computer intercept techniques used in this program were capable of modifying secondary air and EGR without setting any on-board diagnostic codes. The modified control strategies also did not have any measurable impact on fuel economy, nor were any detectable changes to vehicle driveability observed during FTP evaluations.

After these modifications, all three vehicles met the Tier 2 NMOG useful life design targets. The LeSabre and T100 both met the NO_x design target. The Crown Victoria, however was a little short of the design target, but did meet the Tier 2 standard with a headroom of 23 percent. The actual test results are summarized in Table IV-5 below.

Table IV-5. MECA Test Program: Emissions with Catalysts Aged to 100,000 Miles (g/mi).

	<i>NMOG</i>	<i>NO_x</i>
Tier 2 Design Targets	0.045-0.063	0.035-0.049
Crown Victoria (LDV)	0.049	0.057
Buick LeSabre (LDV)	0.038	0.037
Toyota T100 (LDT2)	0.052	0.014

iv. CARB Test Program

CARB tested five different 1997-98 model year production LEV LDV models. Two of the five models met the Tier 2 design targets for NMOG and NO_x. Each vehicle was tested for baseline emissions at approximately 1K miles before any modifications to the vehicle's emission controls were made. Table IV-5 lists the average emissions from these FTP tests.

Table IV-6. CARB Production LEV LDV Passenger Car Emission Data.

<i>Test Vehicle</i>	<i>NMHC (g/mi)</i>	<i>CO (g/mi)</i>	<i>NO_x (g/mi)</i>
1997 Mercury Sable	0.035	0.9	0.072
1998 Mercury Grand Marquis	0.048	0.6	0.014
1998 Nissan Altima	0.031	0.7	0.040
1998 Honda Accord EX	0.025	0.3	0.066
1998 Toyota Avalon	0.044	0.4	0.111

After the baseline FTP results were complete, new advanced catalysts supplied by various catalyst suppliers were installed on each test vehicle. In general, the advanced catalysts were placed in the same position as the OEM catalysts. Two of the vehicles had small close-coupled catalysts added to the OEM configuration. FTP tests were then conducted. If the emission results were not below the LEV II standards with a reasonable margin, engine calibration modifications such as spark retard at engine start, O₂ sensor biasing (typically rich), or secondary air injection modifications were made to reduce tailpipe emission levels further. In a couple of instances, approximately 4K miles were accumulated on the "green" catalysts before FTP tests were conducted again. All of the vehicles, once modified, had emission levels well below the Tier 2 NMOG and NO_x emission standards. While these results are not with catalysts aged to

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full useful life, we believe these results are still very promising, since in-use deterioration rates have been steadily declining. Even if these emissions were to double, they would still be very close to or below the Tier 2 standards. Table IV-7 lists the modified passenger car emission results.

**Table IV-7. ARB Modified Passenger Car Emission Data
(advanced catalysts with modifications to fuel and/or spark & secondary air)**

<i>Manufacturer</i>	<i>Model</i>	<i>Mileage</i>	<i>NMOG (g/mi)</i>	<i>CO (g/mi)</i>	<i>NOx (g/mi)</i>
Mercury	Sable	0	0.029	1.0	0.036
Mercury	Grand Marquis	4000	0.033	0.5	0.004
Nissan	Altima	0	0.028	0.7	0.033
Honda	Accord EX	0	0.026	0.4	0.035

ARB also tested two identical 1998 Ford Expeditions (LDT4). Both vehicles were tested in the baseline OEM configuration at 2,000 miles with promising results. Table IV-8 lists the baseline emission results for the two Expeditions.

Table IV-8. CARB Ford Expedition Baseline Emission Test Results

<i>Vehicle</i>	<i>No. of Tests</i>	<i>NMHC (g/mi)</i>	<i>CO (g/mi)</i>	<i>NOx (g/mi)</i>
#2	8	0.090	1.69	0.030
#3	6	0.077	1.57	0.031

ARB installed advanced Pd/Rh catalyst systems bench aged to 50,000 miles along with 50,000 mile bench aged oxygen sensors on both vehicles and were able to reduce NOx emissions about 50 percent from the NOx certification level of 0.14 g/mi. CARB also added secondary air to the vehicles and made some modifications to the spark timing (retarded) and oxygen sensor bias (rich) and found that they were able to further reduce emissions. Table IV-9 lists the emission results of the Expeditions with advanced catalyst systems.

Table IV-9. CARB Expedition Emission Results with Advanced Catalyst Systems

<i>Vehicle</i>	<i>No. Of Tests</i>	<i>NMHC (g/mi)</i>	<i>CO (g/mi)</i>	<i>NOx (g/mi)</i>
#2	4	0.111	3.32	0.048
#3	7	0.112	2.91	0.052

- *EPA Test Program*

Our test program was aimed at lowering the emissions of large 1999 LDT3 and LDT4 heavy-light-duty trucks to levels at or below those of the Tier 2 Standards at intermediate life (50,000 miles). All of the vehicles tested had large displacement (greater than 5.3 liter), high horsepower (230-270 hp) engines; four wheel drive; curb weights of 4,500 to 5500 pounds; and gross vehicle weights of greater than 6,000 lbs. Specifications of the trucks tested are included in table IV-10.

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Table IV-10: EPA Test Vehicle Specifications

<i>Trucks Tested</i>	<i>Test Weight (lbs.)</i>	<i>Engine</i>	<i>Drivetrain</i>	<i>Intermediate Useful Life (50,000 mile) Certification Levels</i>		
				<i>NMOG (g/mi)</i>	<i>CO (g/mi)</i>	<i>NOx (g/mi)</i>
1999 Ford Expedition LEV	5876	5.3L V8, 230 bhp	4-speed Auto., 4-WD	0.09	1.7	.07
1999 GM Chevrolet Silverado LEV	4818	5.4 L V8, 270 bhp	4-speed Auto., 4-WD	0.11	2.4	0.3

A key element of the test was the alteration of engine calibration parameters of the powertrain control module (PCM), which included modification of spark timing, EGR, and fuel control. During testing at EPA-NVFEL, flash-reprogramming of the PCM, off-board ROM, and ROM emulation were used to accomplish PCM calibration changes. All of the catalysts/exhaust systems evaluated were thermally aged to an equivalent 50,000 miles using the vehicle manufacturers' specific catalyst aging cycle.

Specifications of some of the exhaust catalyst systems tested in this program can be found in table IV-11.

Table IV-11: Catalyst Specifications

		<i>Ford Expedition</i>		<i>GM Chevrolet Silverado</i>	
<i>Catalyst Configuration</i>		<i>EXP1 (stock OEM)</i>	<i>EXP3</i>	<i>SILV1 (stock OEM)</i>	<i>SILV2</i>
Total Catalyst Volume (L)		5.3	5.9	4.8	3.9
Total No. of Catalyst Bricks		6	6	4	6
Total Pd Loading (g)		17.2	26.4	4.6	69
Total Rh Loading (g)		0.82	4.18	0.28	4.94
Front Bricks	Volume (L)	0.69	0.69		0.345
	Pd Loading (g)	4.87	4.87		12.17
	Cell Density (cells/in ²)	400	400		600
	Wall Thickness (mil)	6	6		4
Middle Bricks	Volume (L)	1.06	1.26	1.2	0.695
	Pd Loading (g)	2.02	4.45	1.29	13.14
	Rh Loading (g)	0.22	1.12	0	1.45
	Cell Density (cells/in ²)	400	600	400	400
	Wall Thickness (mil)	6	4	6	6
Rear Bricks	Volume (L)	0.9	1.01	1.2	0.907
	Pd Loading (g)	1.72	3.88	1.02	9.18
	Rh Loading (g)	0.19	0.97	0.14	1.02
	Cell Density (cells/in ²)	400	600	400	400
	Wall Thickness (mil)	6	4	6	6

Only minor changes were made to the Chevrolet Silverado PCM calibration. These included:

- 4 to 6 degree spark timing retard under cold-start conditions to improve catalyst light-off times

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- Earlier enablement of EGR after cold-start, using the original EGR map

The majority of the emissions improvement on the tested Silverado configurations are due to increased precious metal loading of the exhaust catalysts tested. No measurable differences in fuel economy were noted after the changes. Driveability was not affected. The final tested configuration of the Chevrolet Silverado achieved NO_x emissions of 0.05 g/mi and NMHC emissions of 0.06 g/mi, meeting the Tier 2 standard.

The availability of ROM emulation for the Ford Expedition allowed considerable PCM calibration tuning to be performed both on the chassis dynamometer and while driving on the highway. The tested Expedition configurations relied considerably more on calibration tuning than the Silverado.

We found that more than 80 percent of the NO_x and NMHC emissions from the Expedition occurred during the first 30 seconds after a cold start. Therefore, most of the calibration tuning focused on reducing NO_x and NMHC emissions from the cold start portion, or “phase 1”, of the light-duty FTP. Some of the calibration changes included:

- 15 to 20 degree spark timing retard under cold-start conditions to improve catalyst light-off times
- Minor spark timing retard to increase catalyst temperatures at lighter load, lower speed conditions
- Earlier enablement of EGR (enabled after ~30 seconds under typical FTP cold-start conditions)
- Increased EGR rates, particularly at part load conditions
- Extension of the EGR map to cover higher-speed, higher load driving conditions

The retarded spark timing initially after cold start resulted in increased front catalyst brick temperatures, which were increased from 425 °C to 550 °C at 30 seconds after cold start. Considerable EGR tuning approximately halved engine-out (pre-catalyst) NO_x emissions. Maximum EGR rates did not exceed 14 percent, and were considerably less for most operating conditions. Engine-out CO was unchanged by the additional EGR. Engine-out HC was increased by 5 to 15 percent. The engine-out HC increase due to additional EGR was more than offset by higher catalyst efficiency due to the higher PGM loading and volume of the underfloor catalyst, and due to the increased catalyst temperatures immediately after cold-start from the cold spark retard.

Cold start NO_x performance was further improved by the use of low-mass, sealed-air-gap, tubular-steel exhaust manifolds. The prototype manifolds further increased front catalyst brick temperatures from 550 °C to 630 °C at 30 seconds after cold start. Catalyst brick temperatures did not exceed 850 °C for any of the tested configurations, even over the US06 cycle. The reliance on Pd and Pd/Rh formulations, and stabilized cerium oxide, allowed a safe margin with respect to catalyst brick temperatures. Catalyst manufacturers have indicated to us that current catalyst formulations can typically withstand temperatures of 950 °C to 1000 °C without

damage.

Considerable tuning of the PCM calibration was also used to minimize impacts of the calibration changes on driveability and fuel economy. The final calibrations achieved considerable improvements in emissions performance with no measurable impact on fuel economy and no perceptible change in driveability. The Expedition achieved NO_x emissions of 0.04 g/mi and NMHC emissions 0.07 g/mi with the OEM cast exhaust manifolds, and 0.02 g/mi NO_x, 0.07 g/mi NMHC with the sealed-air-gap exhaust manifolds. The final tested configurations easily met the Tier 2 NO_x standard. The NMHC emissions meet the 50,000 mile standard. Use of close-loop controlled secondary-air-injection (similar to that used by SwRI for the MECA test program) would further reduce cold-start NMHC emissions with only a minor degradation in NO_x performance.

In addition to testing at EPA, a virtually identical 1999 Ford Expedition was tested under an EPA contract at Southwest Research Institute (SwRI) using the ERIC system to facilitate calibration changes. The exhaust catalyst system tested was identical to the system tested by ARB with a 1998 Ford Expedition (see section iv). Data from a 1999 Chevrolet Silverado similar to the vehicle tested at NVFEL was provided by MECA. This vehicle was also tested at SwRI using the ERIC system to provide engine calibration changes. Emissions from the trucks tested at NVFEL and at SwRI for a number of the tested exhaust catalyst and engine calibration configurations are compared in figures IV-2 and IV-3. The trucks tested at SwRI achieved approximately the same low emissions levels as those tested at NVFEL, even though their mix of hardware and calibration changes were relatively different. The low emissions levels achieved essentially demonstrate the feasibility of the Tier 2 standards for heavy-light-duty trucks and the ability to achieve those standards using a variety of logical engineering paths.

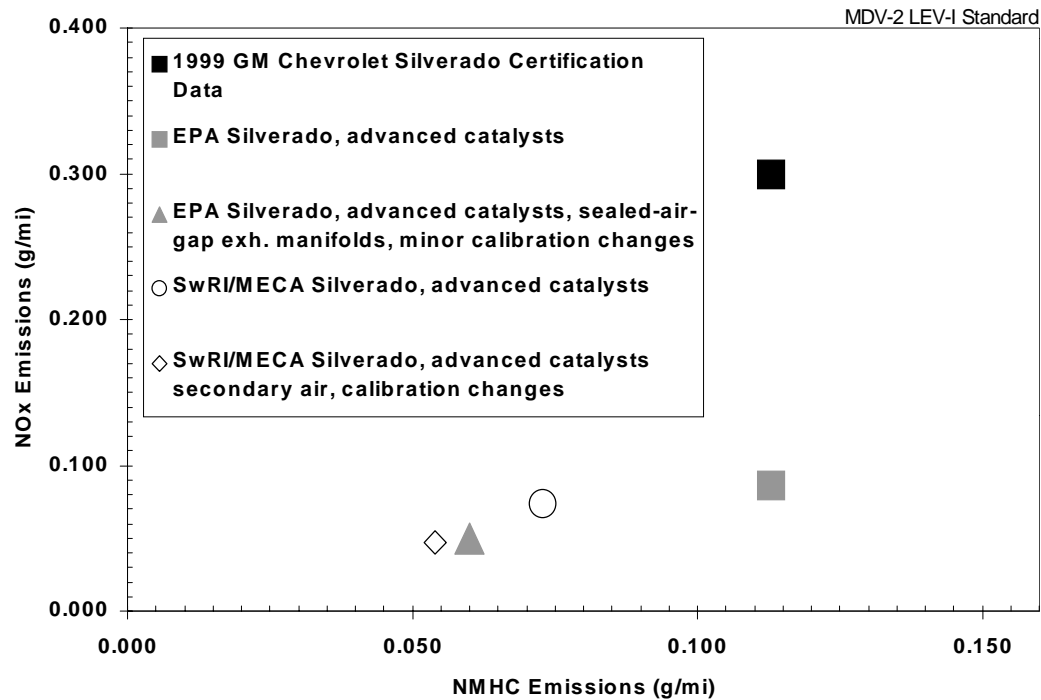


Figure IV-2: 50,000 mile equivalent NOx vs. NMHC levels for a number of hardware and engine calibration configurations tested with a 1999 GM Chevrolet Silverado Pickup (5.3L V8) originally certified to the LEV MDV-2 standard (0.4 g/mi NOx, 0.16 g/mi NMOG).

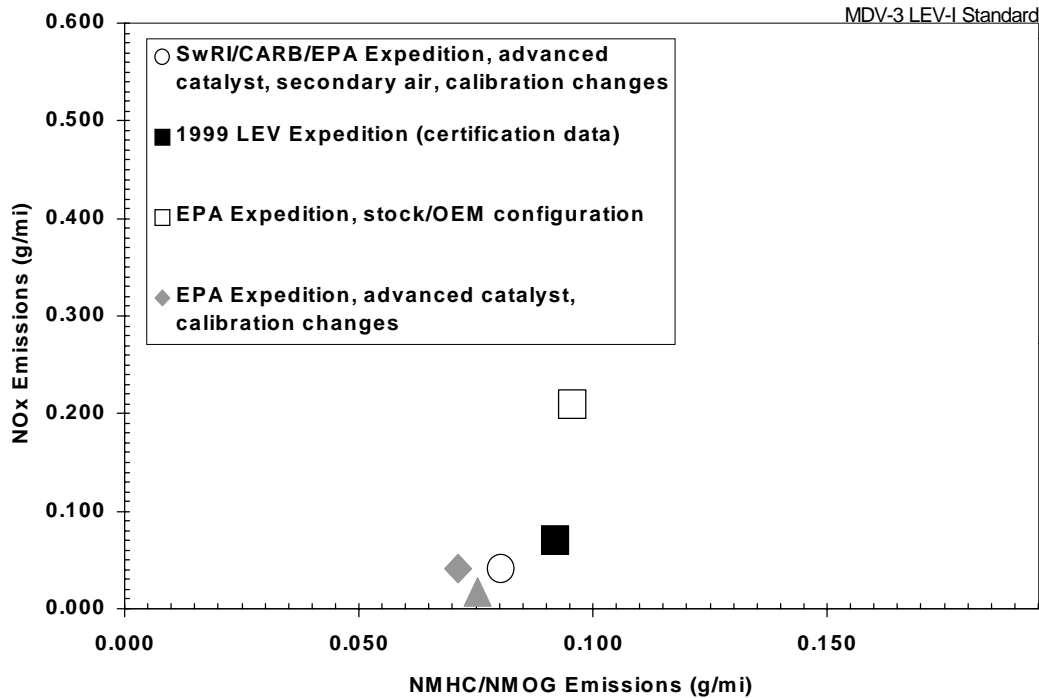


Figure IV-3: 50,000 mile equivalent NO_x vs. NMHC emissions levels for a number of hardware and engine calibration configurations tested with a 1999 Ford Expedition (5.4L V8) originally certified to the LEV MDV-3 standard (0.6 g/mi NO_x, 0.195 g/mi NMOG).

The technologies and emission control strategies that will be used for LDT3 and LDT4 vehicles should also apply directly to medium-duty passenger vehicles (MDPVs), which have a GVWR greater than 8,500 pounds. In our LDT technology demonstration program discussed above, we found that a combination of calibration changes and improvements to the catalyst system resulted in emission levels for NO_x well below and NMHC/NMOG approximately at the Tier 2 intermediate useful life standards. The catalyst improvements consisted of increases in volume and precious metal loading, and higher cell-densities than those found in the original hardware. We are confident that the use of secondary-air-injection will greatly help cold-start hydrocarbon control, making the NMOG standards achievable.

The most significant difference between LDT4s and MDPVs is that MDPVs have a vehicle weight up to 800 pounds more than LDT4s. MDPVs will also be typically equipped with larger displacement engines. The potential impact of these differences is higher engine-out

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emissions than LDT4s due to the larger engine displacement and greater load that the engine will be operated under due to the extra weight. However, neither of these preclude manufacturers from applying the same basic emission control technologies and strategies as used by LDVs and LDTs. The only difference will likely be the need for larger catalysts with higher precious metal loading than found in LDT4s. We are confident that MDPVs will be capable of meeting the Tier 2 standards.

We are currently testing a Ford Excursion as part of our LDT technology demonstration program. Preliminary baseline results with a green (i.e., “new”) catalyst indicate that emission levels are higher than baseline emissions for the Ford Expedition. These results, although with a green catalyst, are well below our interim Tier 2 upper bin standards. In fact, the majority of these vehicles certified on the chassis dynamometer in California, have certification levels well below our interim upper bin standards. We have also tested the Excursion at loaded vehicle test weight (curb + 300 lb) and again at adjusted loaded vehicle weight (half payload) and found that the engine-out and tailpipe emission results for NMHC and NO_x were the same for the two test weights. In other words, the additional weight (approximately 700 lbs) had no impact on emission performance. This suggests that challenge for MDPVs in meeting Tier 2 standards may not be as difficult as originally believed.

While this testing is still ongoing, we feel that the preliminary results are encouraging since they suggest that the additional weight for these vehicles may not be as significant as originally thought, and the difference in emission results between the Excursion and Expedition suggest that the strategies used on the Expedition can be successfully employed with the Excursion. Therefore, we believe that by using technologies and control strategies similar to what will be used by LDVs and LDTs, combined with larger catalysts, MDPVs will be able to meet our Tier 2 emission standards.

c. Lean-Burn Technology

The above discussion focused on advancements in emission control technology. New gasoline engines designs are also being developed to reduce fuel consumption. In particular, gasoline direct-injection (GDI) engines have been developed (and are being sold in Japan and Europe) which operate on 10-20 percent less fuel than today’s gasoline engines.

One of the reasons that these engines use less fuel is that they use much more air than is needed just to burn the fuel. In this respect, they operate similar to a diesel engine. While this is advantageous for fuel efficiency, it makes it more difficult to eliminate NO_x emission using aftertreatment technology. Highly efficient 3-way catalysts require that there be little excess oxygen in the exhaust stream in order to convert NO_x emissions to nitrogen and oxygen. Unfortunately, if a GDI engine is operated in this way, nearly all of its fuel efficiency benefits are lost.

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A number of potential techniques are being developed to control NO_x emissions when excess air is present. These techniques are discussed in more detail in Section 5 below. The most promising of these techniques for GDI engines are the lean NO_x catalyst and the NO_x adsorber. As part of the ongoing efforts in developing GDI technology, substantial progress is being made in the application of aftertreatment controls. While much remains to be done both in lowering engine-out emission levels and in aftertreatment development, we believe that the bin structure in the Tier 2 standards is sufficient to allow the introduction of GDI engines.

2. CO Emissions from Gasoline Fueled Vehicles

EPA is only requiring tighter CO emission standards for LDT2s, LDT3s, LDT4s and MDPVs. Basically, CO emissions from these vehicles must be reduced to the levels now required for LDVs and LDT1s under the NLEV program. Also, LDVs and LDT1s must comply with the NLEV CO standards over a slightly longer useful life of 120,000 miles instead of the current useful life of 100,000 miles.

Compliance with the Tier 2 CO emission standards should not be difficult given compliance with the Tier 2 NMOG standards. The control of both pollutants utilizes much of the same technology and the Tier 2 NMOG standards are the more stringent of the two sets of standards. In addition, the change in test weight from “adjusted loaded vehicle weight” to “loaded vehicle weight” will make it easier to meet the Tier 2 CO emission standards. The following table IV-12 summarizes CO emissions from vehicles certified to the LEV standards in California.

Table IV-12. CO Emissions from California LEVs (g/mi)

<i>LDV/LDT</i>	<i>LDT2</i>	<i>LDT3</i>	<i>LDT4</i>
0.8	1.13	2.35	2.95

As can be seen, the CO emissions from all of these vehicles are well below the Tier 2 CO standard of 4.2 g/mi. While CO emissions from LDT3s and LDT4s are more than half the 4.2 g/mi standard, the current LEV standards for these vehicles is more than twice the Tier 2 NMOG standard of 0.09 g/mi. As NMOG emissions are reduced to meet the 0.09 g/mi standard, CO emissions will decrease further, as well. CO emission control is also not a problem for GDI engines. Thus, compliance with the Tier 2 CO standard should not add any additional burden to manufacturers relative to compliance with the NMOG and NO_x standards.

3. Formaldehyde Emissions from Gasoline Fueled Vehicles

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EPA is only requiring tighter formaldehyde emission standards for LDT2s, LDT3s, LDT4s and MDPVs. Basically, formaldehyde emissions from these vehicles must be reduced to the levels now required for LDVs and LDT1s under the NLEV program. Also, LDVs and LDT1s would have to comply with the NLEV formaldehyde standards over a slightly longer useful life of 120,000 miles versus the current 100,000 mile useful life.

Again, as with CO emissions, compliance with the Tier 2 formaldehyde emission standards should not be difficult given compliance with the Tier 2 NMOG standards. The control of both pollutants utilizes the same technology and the Tier 2 NMOG standards are the more stringent of the two sets of standards. Table IV-13, below, summarizes formaldehyde emissions from vehicles certified to the LEV standards in California.

Table IV-13. Formaldehyde Emissions from California LEVs (g/mi)

<i>LDV</i>	<i>LDV/LDT1</i>	<i>LDT2</i>	<i>LDT3</i>	<i>LDT4</i>
0.0012	0.0016	0.0013	0.002	0.002

As can be seen, formaldehyde emissions from current California vehicles are roughly a factor of 10 below the Tier 2 formaldehyde standard of 0.018 g/mi. Thus, compliance with the Tier 2 formaldehyde standard should not add any additional burden to manufacturers relative to compliance with the NMOG and NO_x standards.

4. Evaporative Emissions

The Tier 2 standards for evaporative emissions are technologically feasible now. Many designs have been certified by a wide variety of manufacturers that already meet these standards. A review of the 1999 model year certification results indicates that the average family is certified at less than 1.0 grams per test on the 3 day diurnal plus hot soak test, i.e. at less than half the current 2.0 g/test standard.

The Tier 2 standards will not require the development of new materials or, in many cases, even the new application of existing materials. Low permeability materials and low loss connections and seals are already used to varying degrees on current vehicles. Today's standards will likely ensure their consistent use and discourage manufacturers from switching to cheaper materials or designs to take advantage of the large safety margins they have under current standards ("backsliding").

There are two approaches to reducing evaporative emissions for a given fuel. One is to minimize the potential for permeation and leakage by reducing the number of hoses, fittings and

connections. The second is to use less permeable hoses and lower loss fittings and connections. Manufacturers are already employing both approaches.

Most manufacturers are moving to “returnless” fuel injection systems, and at least one major manufacturer utilizes returnless systems on all of their vehicles. Through more precise fuel pumping and metering, these systems eliminate the return line in the fuel injection system which carries unneeded fuel from the fuel injectors, which has been heated from its close proximity to the hot engine, back to the fuel tank. Returned fuel is a significant source of fuel tank heat and vapor generation. The elimination of return lines also reduces the total length of hose on the vehicle and also reduces the number of fittings and connections which can leak.

Low permeability hoses and seals as well as low loss fittings are available and are already in use on many vehicles. Fluoropolymer materials can be added as liners to hose and component materials to yield large reductions in permeability over such conventional materials as monowall nylon. In addition, fluoropolymer materials can greatly reduce the adverse impact of alcohols in gasoline on permeability of evaporative components, hoses and seals.

5. Diesel Vehicles

As discussed earlier, the Tier 2 standards are intended to be “fuel neutral.” In this document, we establish that the Tier 2 standards are technologically feasible and cost-effective for LDVs and LDTs overall. Under the principal of fuel neutrality, all cars and light trucks, including those using diesel engines, will be required to meet the Tier 2 standards. Contrary to some of the comments received on our proposal, given that the overwhelming majority of vehicles in these classes are gasoline-fueled, we do not believe it is appropriate to provide less stringent standards for diesel-fueled vehicles. Manufacturers of LDVs and LDTs today provide consumers with a wide choice of vehicles that are overwhelmingly gasoline-fueled. Less stringent standards for diesels would create provisions that could undermine the emission reductions expected from this program, especially given the expectation that some manufacturers are hoping to greatly increase their diesel sales.

As with gasoline engines, manufacturers of diesels have made abundant progress over the past 10 years in reducing engine-out emissions from diesel engines. In heavy trucks and buses, PM emission standards, which were projected to require the use of exhaust aftertreatment devices, were actually met with only engine modifications. Indeed, emissions and performance of lighter diesel engine are rapidly approaching the characteristics of gasoline engines, while retaining the durability and fuel economy advantages that diesels enjoy. Against this background of continuing progress, we believe that the technological improvements that would be needed could be made in the time that would be available before diesels would have to meet the new Tier 2 standards.

Manufacturers may take advantage of the flexibilities in our Tier 2 emission standards to

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delay the need for diesel LDVs and LDTs to meet the final Tier 2 levels until late in the phase-in period (as late as 2007 for LDVs/LLDTs and 2009 for HLDTs), giving manufacturers a relatively large amount of leadtime. In a recent public statement, Cummins Engine Company has indicated that the interim Tier 2 standards in effect for vehicles and trucks in the early years of the Tier 2 program are feasible for diesel equipped models through further development of currently available engine technology.² We also believe that standards can be met through the use of existing technologies, such as cooled EGR where it currently is not used, moderate amounts of fuel injection timing retard, and perhaps limited use of lean NOx catalysts and/or diesel oxidation catalysts, as well as particulate traps.

NOx and PM are the two biggest emission-related challenges for diesel engines. Diesels have inherently low emissions of CO and NMOG and should have no problem meeting the Tier 2 standards for these pollutants. Engine-out emissions continue to be reduced. The following are some examples of technologies and strategies that can be used to reduce engine-out emissions.

One of the most important control strategies for the reduction of engine-out NOx emissions is the addition of cooled exhaust gas recirculation (cooled EGR). This method recirculates a portion of the exhaust back to the intake manifold where it is drawn into the combustion chamber. The resulting mixture of fresh air and exhaust products has a lower concentration of O₂ than fresh air alone. The lower concentration of O₂ in the combustion chamber results in lower O₂ partial pressure which lowers its propensity to oxidize N₂ to NO and NO₂ (NOx) during the combustion process.

More sophisticated electronic control systems will be necessary to control the EGR system. EGR control algorithms will require additional engine condition information, possibly including mass air flow, oxygen, NOx, or EGR valve position sensors. These inputs will be necessary to control the EGR rate via an EGR valve or possibly a variable geometry turbocharger (VGT). These turbochargers will also require a sophisticated control algorithm to take advantage of their transient response, EGR pumping, and air flow control characteristics. In addition, the turbomachinery used with EGR will likely be pushed near the limits of its capability, and the engine's electronic control module (ECM -- the engine's control computer) will need to ensure the limits of the hardware are not exceeded.

While reductions in "engine-out" emissions may continue to be made, increasing emphasis is being placed on various aftertreatment devices for diesels. We believe that the use of aftertreatment devices alone will allow diesels to comply with the Tier 2 standards for NOx and PM.

²"Cummins Sees Diesel Feasible for Early Years of Tier 2". Hart Diesel Fuel News, Sept. 20, 1999, p.2.

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For NOx emissions, potential aftertreatment technologies include lean NOx catalysts, NOx adsorbers and selective catalytic reduction (SCR). Lean NOx catalysts are still under development, but generally appear capable of reducing NOx emissions by about 15-30 percent. This efficiency is not likely to be sufficient to enable compliance with the final Tier 2 standards, but it could be used to meet the interim standards that would begin in 2004.

NOx adsorbers appear capable of reaching efficiency levels as high as 90 percent. Efficiency in this range is likely to be sufficient to enable compliance with the proposed Tier 2 standards. NOx adsorbers temporarily store the NOx and thus the engine must be run periodically for a brief time with excess fuel, so that the stored NOx can be released and converted to nitrogen and oxygen using a conventional three-way catalyst, like that used on current gasoline vehicles.

There is currently a substantial amount of development work being directed at NOx adsorber technology. While there are technical hurdles to be overcome, progress is continuing and it is our judgement that the technology should be available by the time it would be needed for the final Tier 2 standards.

One serious concern with current NOx adsorbers is that they are quickly poisoned by sulfur in the fuel. Some manufacturers have strongly emphasized their belief that, in order to meet the final Tier 2 levels, low sulfur diesel fuel would also be required to mitigate or prevent this poisoning problem. In its comments on the NPRM, Navistar indicated that the Tier 2 standards may be achievable given low sulfur fuel and other programmatic changes such as those included in this Final Rule. Navistar has also been quoted publicly as describing the Tier 2 standards as “challenging but achievable” given appropriate low sulfur fuel.³

One solution would be to reduce sulfur to very low levels. Another solution would be to reduce sulfur somewhere below current levels and develop a way to periodically remove the sulfur from the adsorber. In any event, this technique, if used, would also require low sulfur diesel fuel. We will be issuing a Notice of Proposed Rulemaking in the near future intended to reduce sulfur in highway diesel fuel on a parallel path with today’s final rule as a step to enable the technology most likely to be used to meet the Tier 2 standards.

SCR has been demonstrated commercially on stationary diesel engines and can reduce NOx emissions by 80-90 percent. This efficiency would be sufficient to enable compliance with the proposed Tier 2 standards. However, SCR requires that the chemical urea be injected into the exhaust before the catalyst to assist in the destruction of NOx. The urea must be injected at very precise rates, which is difficult to achieve with an on-highway engine, because of widely varying engine operating conditions. Otherwise, emissions of ammonia, which have a very objectionable

³Harts Diesel Fuel News, August 9, 1999, p4.

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odor, can occur. Substantial amounts of urea are required, meaning that vehicle owners would have to replenish their vehicles' supply of urea frequently, possibly as often as every fill-up of fuel. As the engine and vehicle will operate satisfactorily without the urea (only NO_x emissions would be affected), some mechanism would be needed to ensure that vehicle owners maintained their supply of urea. Otherwise, little NO_x emission reduction would be expected in-use.

Regarding PM, applicable aftertreatment devices tend to fall into two categories: oxidation catalysts and traps. Diesel oxidation catalysts look very similar to the 3-way catalysts used on gasoline vehicles. Diesel catalysts convert the hydrocarbon compounds in the exhaust to water and carbon dioxide. This reduces exhaust NMOG emissions and heavier HC compounds which comprise about 30 percent of total PM mass emissions. The oxidation catalyst can be from 50 percent to 90 percent effective at converting HC. Thus, an oxidation catalyst can reduce total PM emissions by roughly 15-30 percent. By itself, the oxidation catalyst is not likely to be sufficient to enable compliance with the Tier 2 standards without further advancements in engine technology.

Traps can eliminate up to 90 percent of diesel PM emissions. The trap first filters the carbonaceous particles from the exhaust. Then, periodically, this trapped PM must be burned, or the trap will fill up and cause problems in operating the engine. Diesel traps are currently being used on buses in a number of U.S. cities. It appears that these traps can regenerate frequently enough given the operating temperatures of bus engines and over-the-road trucks. However, there is some question whether or not these traps could regenerate frequently enough with the somewhat lower operating temperatures of diesel engines in LDVs and LDTs. Regeneration can be enhanced at lower exhaust temperatures through the use of more active catalysts on the surface of the trap. However, these catalytic materials convert sulfur dioxide in the exhaust to sulfuric acid. Thus, their use requires the removal of most of the sulfur in the fuel. Research indicates that low temperature regeneration may also be enhanced through the use of catalytic fuel additives comprised of cerium or iron. However, particulate containing these chemicals can be emitted from the tailpipe, raising some health concerns. Use of these catalytic fuel additives does not require the removal of sulfur from diesel fuel. An efficient trap should enable compliance with the Tier 2 PM standards.

In summary, we believe that the structure of our final program, including the available bins and phase-in periods, will allow the orderly development of clean diesel engine technologies. We believe that the interim standards are feasible for diesel LDV/LDTs, within the bin structure of this rule and without further reductions in diesel fuel sulfur levels. And, as indicated earlier, at least one major diesel engine manufacturer (Cummins) has publically agreed with this assessment. We further believe that in the long-term, the final standards will be within reach for diesel-fueled vehicles in combination with appropriate changes to diesel fuel to facilitate aftertreatment technologies. Manufacturers have argued that low sulfur diesel fuel will be required to permit diesels to meet the final Tier 2 standards, and we agree. Once again, at least one major manufacturer (Navistar) has indicated its belief that the final Tier 2 standards

may be achievable for diesel engines with low sulfur diesel fuel.

B. Feasibility of Removing Sulfur from Gasoline

1. Source of Gasoline Sulfur

Sulfur is in gasoline because it naturally occurs in crude oil. Crude oil contains anywhere from fractions of a percent of sulfur, such as less than 0.05 weight percent (0.05 percent is the same as 500 ppm) to as much as several percent.² The average amount of sulfur in crude oil refined in the U.S. is about one percent.³ Most of sulfur in crude oil is in the heaviest part, or in the heaviest petroleum compounds, of the crude oil (outside of the gasoline boiling range). In the process of refining crude oil into finished products, such as gasoline, some of the heavy compounds are broken up into smaller compounds, or cracked, and the embedded sulfur ends up in gasoline. Thus, the refinery units which convert the heavy parts of crude oil into gasoline are the units most responsible for putting sulfur into gasoline.

The fluidized catalytic cracker (FCC) unit is the refinery processing unit most responsible for moving sulfur into gasoline. The FCC unit cracks large carbon molecules into smaller ones and produces anywhere from 30 to 50 percent of the gasoline in most refineries. Because the FCC unit makes gasoline out of the heavier, higher sulfur-containing compounds, more than 90 percent of sulfur in gasoline comes from streams produced in that unit.⁴

Another refinery unit which is responsible for a significant amount of sulfur in gasoline is the coker unit. These units produce coke from the heavy part of the crude oil. In the process of producing coke, some gasoline blendstocks are produced and some of these blendstocks are blended directly into gasoline (much of it is hydrotreated and processed further before blending into gasoline). While the volume of gasoline blendstock produced by the coker is small (normally less than one percent of the gasoline pool), this stream usually contains more than 3000 ppm sulfur,⁵ so the contribution of sulfur to gasoline is significant.

Another gasoline blendstock which contributes sulfur to gasoline is the straight run. Straight run is the portion of the crude oil which falls in the gasoline boiling range which is blended directly into gasoline. Usually only the light straight run is blended into gasoline which has a small amount of sulfur (i.e., on the order of 100 ppm sulfur), although in trying to meet a low sulfur standard, even this amount sulfur becomes significant. The heaviest portion of straight run, which would have more sulfur, is normally desulfurized and reformed in the reformer (to improve its octane), so its contribution to the gasoline pool is virtually nil. Alkylate is another stream which can have enough sulfur worth mentioning. Most refineries have less than five ppm sulfur in this pool, however, some refineries which feed coker naphtha to the alkylate plant can have much more. On average, alkylate probably has about 10 ppm sulfur. Other gasoline blendstock streams with either very low or no sulfur are hydrocrackate, and isomerate. Oxygenates which are blended into gasoline usually have very little or no sulfur,

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however, during shipping through pipelines, they can pick up some sulfur. The implementation of a low gasoline sulfur standard, though, would reduce much of the sulfur which oxygenates could pick up in the pipeline.

Since FCC units and cokers contribute so much sulfur to gasoline, then a simplistic conclusion which could be reached would be that refiners could simply shut down these units in their refineries to meet a low sulfur standard. This conclusion is not reasonable considering the quality of crude oil which is used today and the products demanded of the oil industry. Much of the volume of crude oil is composed of heavy compounds which have no end use, and thus is not usable without processing by these units. These units make marketable products from what would otherwise be a waste oil stream.

2. Current Levels of Sulfur in Gasoline

It is important to know the amount of sulfur in gasoline for determining the most cost-effective sulfur removal methods for our cost analysis, and for developing the gasoline sulfur phase-in requirements. For the NPRM, we used a mixture of gasoline sulfur data from the American Petroleum Institute (API) and the National Petrochemical Refiners Association (NPRA) survey which was conducted during the Summer of 1996,⁶ and 1995, 1996 and 1997 gasoline sulfur data from the RFG data base. To enable our cost analysis, we compiled the data by various regions called Petroleum Administrative Districts for Defense (PADDs), as well as for the country as a whole. (These PADDs are illustrated below in Figure IV-2)

Petroleum Administration for Defense (PAD) Districts

Figure IV-4. Map of U.S. Petroleum Administrative Districts for Defense

The API/NPRA study showed that the gasoline sulfur, outside of California, averaged 340 ppm during the Summer of 1996. When looking closer at the information provided in the report, we discovered that some PADD sulfur levels calculated from the API/NPRA data were not in agreement with some of the average blendstock sulfur levels presented within the same report, nor was it consistent with data reported to EPA for the RFG program in 1995 and 1996. One possible reason for the disagreement between the API/NPRA gasoline pool sulfur level and that reported to the RFG data base is that API and NPRA only surveyed refiners for their summertime gasoline qualities. Another possible reason for the discrepancy is a difference in the specific refiners included in the two sets of data. Some refiners did not participate in the API/NPRA survey (especially in PADDs 1 and 5), while data handling complications precluded the inclusion of gasoline sulfur data from some refiners from being reported in the RFG data base. The RFG data base contains year-round data and because it often represents a larger portion of the gasoline sulfur pool, when the sulfur levels were compared between the two data bases, or when the API/NPRA information was compared internally, and there was disagreement, then the RFG data were used in lieu of the API/NPRA survey information.

For the Final Rule, we analyzed the 1998 RFG fuel quality reports to determine the gasoline sulfur levels for 1998. The analysis revealed that during 1998 national gasoline sulfur levels were significantly lower than the sulfur levels in 1997 and previous years. The most likely

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reason why the sulfur levels are lower in 1998 is related to the certification requirements for both RFG and conventional gasoline which changed in 1998. Prior to 1998, RFG was certified using the EPA Simple Model which only required that sulfur not increase relative to each refiner's 1990 baseline level. Regarding conventional gasoline, sulfur levels were simply prevented from increasing by more than 25 percent over the refiner's 1990 baseline level. Starting in 1998, refiners had to use the EPA Complex Model to certify both fuels, which included sulfur's impact on emissions from Tier 0 vehicles. RFG sulfur levels were also capped at 500 ppm starting in 1998. Finally, RFG NO_x emission performance began to be determined relative to the Clean Air Act baseline fuel, which is much cleaner than many refiners' baseline levels.

Since the 1998 data is the best estimate of where refiners will start from in meeting the new sulfur standards, we recalculated our PADD and national average gasoline pool sulfur levels for estimating gasoline desulfurization cost and the phase-in of the low sulfur program based on the new data. Table IV-14 below summarizes the U.S. sulfur levels by PADD, and for the country as a whole used in the NPRM and for this analysis. Because California has its own low sulfur gasoline program, gasoline produced there was excluded from consideration in this analysis.

Table IV-14. Estimated Average Sulfur Levels by PADD and for the Nation.

	<i>PADD 1</i>	<i>PADD 2</i>	<i>PADD 3</i>	<i>PADD 4</i>	<i>PADD 5</i> <i>OC*</i>	<i>U.S.</i> <i>Avg.*</i>
NPRM	215	338	307	265	506	305
FRM	189	276	288	282	301	268

* Outside of California

It is important to note that the gasoline sulfur values reported in Table IV-14 are estimates the average gasoline sulfur level for estimating the cost of desulfurization. In actuality, each sulfur value represents the volumetric average of a range of sulfur values with each refinery representing a single data point. This range can vary from the tens of ppm to almost 1000 ppm. The 1000 ppm sulfur level is the upper limit of the amount of sulfur permitted to be shipped in pipelines in accordance with the American Society for Testing Materials (ASTM) consensus standards.⁷

3. Feasibility of Meeting the Final Gasoline Sulfur Standards

The feasibility of meeting the final standards for low sulfur gasoline can be demonstrated in two distinct ways. The first way is to assess whether there is technology available, or that can reasonably be expected to be available in the lead time provided to the refining industry to meet

the final standard. The second way is to determine if refiners are already demonstrating that they can meet a low sulfur gasoline standard similar to that contained in this final rule. Evidence that a large number of refineries having various configurations are already meeting a stringent gasoline sulfur program is a more compelling example of feasibility since the technology is clearly already available if low sulfur gasoline is already being produced.

It is indeed the case that there are low sulfur gasoline programs already in place. The State of California requires gasoline sold in the State to meet a 30 ppm gasoline sulfur standard on average and a 80 ppm cap, among a number of other fuel standards.⁸ Furthermore, refiners can produce gasoline which varies in composition, provided that the California Predictive Emissions Model (which, like EPA's Complex Model, estimates vehicle emissions from fuels of varying composition) confirms that the proposed fuel formulation meets or exceeds the emissions reduction that would occur based on the default fuel requirements. California refineries are using the flexibility provided by the Predictive Model to surpass the prescriptive standards for gasoline sulfur and are producing gasoline which contains 20 ppm sulfur on average.⁹ They are making this very low sulfur gasoline despite using Californian and Alaskan crude oils which are poorer quality than most other crude oils being used in the U.S. today. Furthermore, the State of California has established tighter gasoline sulfur standards. The average sulfur standard is 15 ppm, with a 60 ppm cap, which takes effect starting January 1, 2003. The cap decreases to 30 ppm starting January 1, 2005.¹⁰ Thus, the experience in California demonstrates that commercial technologies already exist to permit refiners to produce low sulfur gasoline.

In addition to the California experience here in the U.S., a low sulfur requirement in Japan provides additional evidence that reducing gasoline sulfur levels to low levels is feasible. Japanese refineries must meet a 100 ppm per-gallon cap. Based on the gasoline sulfur cap established there, gasoline in Japan averages about 30 ppm sulfur.¹¹

4. Meeting a Low Sulfur Gasoline Standard

a. Background

The methodology that refiners would use to lower their sulfur level depends on a number of factors specific to their refinery. These factors include:

- The gasoline sulfur level prior to the start of the gasoline sulfur program
- The refinery configuration (A typical complex refinery is illustrated in Figure IV-5, below.)
- The amount of excess refinery desulfurization equipment on hand

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- The quality of feedstocks available, especially crude oil
- The quality and types of products produced
- Any plans to change the feedstocks or products of the refinery
- The desulfurization technologies available and their cost
- Other regulatory programs affecting refinery operations in the same time frame

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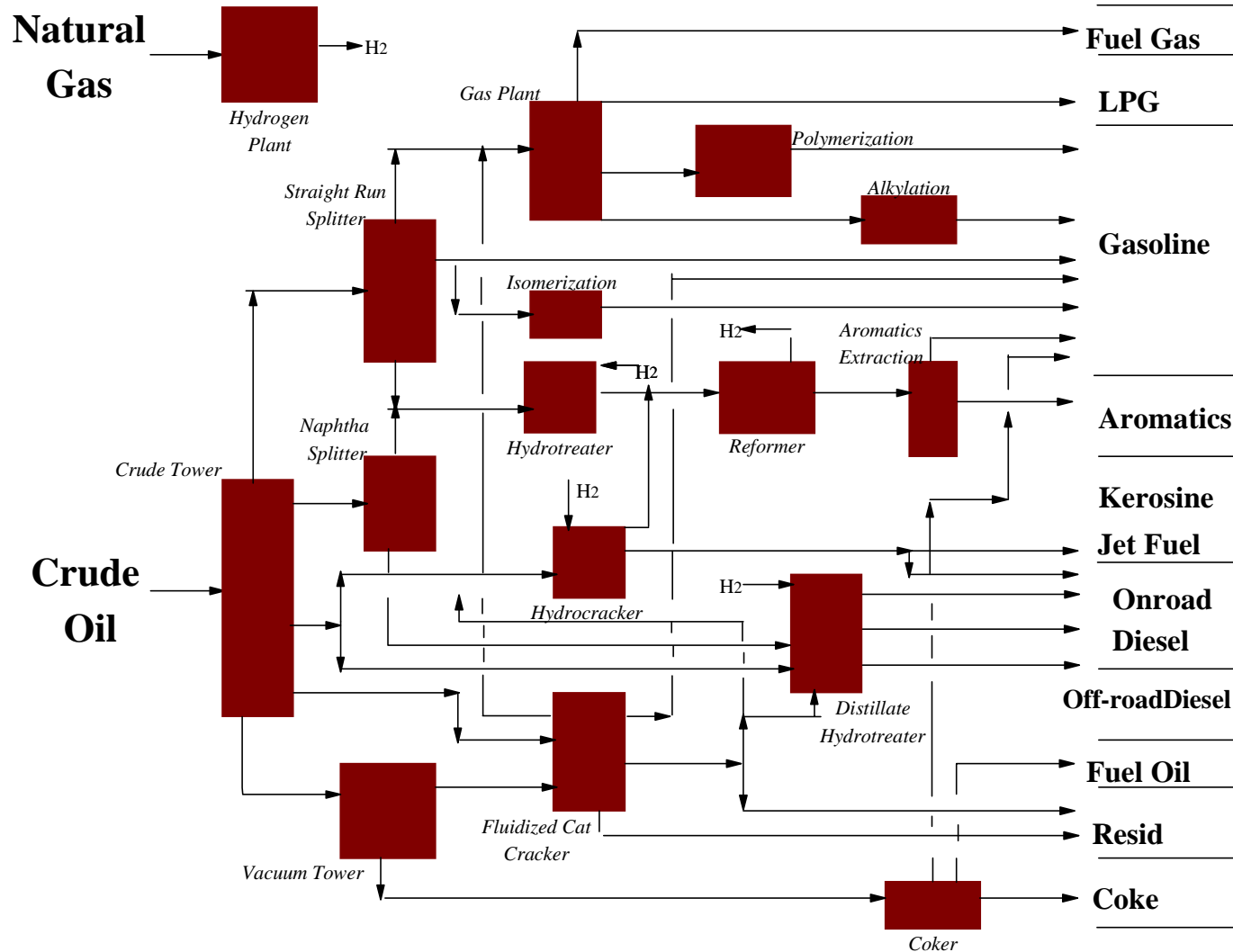


Figure IV-5. Diagram of a Typical Complex Refinery

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A refinery's average gasoline sulfur level is the most important factor determining whether a refiner would need to make a substantial capital investment to meet a sulfur standard. After numerous discussions with refiners, we believe that those refiners with low gasoline sulfur levels to begin with (i.e., gasoline sulfur levels lower than, perhaps, 50 ppm) will probably not need to invest in expensive capital. These refineries have very low sulfur levels due to one or more of a number of possible reasons. For example, some of these refiners may not have certain refining units, such as a fluidized catalytic cracker (FCC) unit, or a coker, which convert heavy boiling stocks to gasoline (Figure IV-5 shows where these units are placed in a refinery). As stated above, these units push more sulfur into gasoline and their absence means less sulfur in gasoline. Alternatively, refiners may use a low sulfur (sweet) crude oil, which results in lower sulfur gasoline. Or, these refiners may have already installed a hydroprocessing unit, such as FCC feed hydrotreating, to improve the operations of their refinery which uses a heavier, higher sulfur (more sour) crude oil. This unit removes much of the sulfur from the heaviest portion of the heavy gas oil before it is converted into gasoline.

Of the refiners in this first category, the refineries with average sulfur levels below 30 ppm would not have to do anything. On the other hand, those refineries with sulfur levels above 30 ppm but below some level, such as 50 ppm, could probably meet the standard employing operational changes only and avoid making capital investments. There are only 3 refineries in this category, representing a total of 2.8% of non-California gasoline production. One such refinery does not have a FCC unit. However, it does have a coker, which produces less gasoline volume than a FCC unit, but the sulfur level of this gasoline can be quite high. This refinery also has extensive hydrotreating capacity. The other two refineries in this situation have FCC units, but also have utilize FCC feed hydrotreating. Thus, all 3 refineries have the capability to desulfurize nearly all of the gasoline components being produced in their refineries. These refiners should be able to meet the 30 ppm sulfur standard by running existing desulfurization units more severely, or by increasing the volume of blendstock sent to these units. If necessary, more active desulfurizing catalysts could be utilized. Refiners also have FCC additives available to them which could allow them to reduce their FCC gasoline sulfur level by 15 to 35 percent, which should be more than sufficient for the two refineries with FCC units.¹² Two of these refineries have average sulfur levels of 40 ppm or less. Thus, they should be able to meet the 80 ppm cap with no change in average sulfur level. They could buy credits (or transfer them from other refineries in their corporation, in the case of multi-refinery refiners) to meet the 30 ppm average standard. Because of their low current sulfur levels, these refineries have until at least 2006, and possibly later in order to implement these strategies. Given the wide range of options available, these 3 refineries should be able to meet the 30 ppm standard without building a desulfurization unit.

The vast majority of gasoline is produced by refineries with higher sulfur levels, and refiners are expected to install capital equipment in these refineries to meet the proposed gasoline sulfur standard. As stated above, the FCC unit is responsible for most of the sulfur in gasoline. Thus, investments for desulfurizing gasoline would likely involve the FCC unit to maximize the

sulfur reduction, and to minimize the cost. This desulfurization capital investment can be installed to treat the gas oil feed to the FCC unit, or treat the gasoline blendstock which is produced by the FCC unit. Each method has advantages and disadvantages.

b. FCC Feed Hydrotreating

FCC feed hydrotreating can be accomplished by a hydrotreater or a mild hydrocracker. These units are designed to operate at high pressures and temperatures to treat a number of contaminants in gas oil. Besides sulfur, FCC feed hydrotreating also reduces nitrogen and certain metals such as vanadium and nickel. These nonsulfur contaminants adversely affect the FCC catalyst, so the addition of this unit would improve the yield of the highest profit-making products such as gasoline and diesel. While FCC feed hydrotreating provides these benefits which partially offsets the costs of adding this type of desulfurization, the costs are still high enough that many refiners would have a hard time justifying the installation of this sort of unit. For a medium to large refinery (i.e., 150,000-200,000 BPCD), the capital costs may exceed \$100 million. Because of the higher temperatures and pressures involved, utility costs are expensive relative to other forms of hydrotreating explained below. Another justification for this approach is that it allows refiners to switch to a heavier, more sour crude oil. These crude oils are less expensive per barrel and can offset the increased utility cost of the FCC desulfurization unit, providing that the combination of reduced crude oil costs and higher product revenues justify the switch. Another benefit for using FCC feed hydrotreating is that the portion of the distillate pool which comes from the FCC unit would be hydrotreated as well. This distillate blendstock, termed light cycle oil, comprises a relatively small portion of the total distillate produced in the refinery (about 20 percent of on-road diesel comes from light cycle oil), like FCC naphtha, light cycle oil contributes a larger portion of the total sulfur which ends up in distillate. Thus, FCC hydrotreating would allow a refiner to produce more low sulfur onroad diesel or meet a lower sulfur standard for onroad diesel, which could apply in the future.

c. FCC Gasoline Hydrotreating

A less expensive alternative for reducing FCC gasoline sulfur levels is FCC gasoline hydrotreating. FCC gasoline hydrotreating only treats the gasoline produced by the FCC unit. Understandably, this unit is much smaller because only about 50 to 60 percent of the feed to the FCC unit ends up as gasoline. The unit is often smaller than that as refiners, which choose to use a fixed bed hydrotreater, could choose to only treat the heavier, higher sulfur portion of that stream with hydrotreating, and then treat the lighter fraction with catalytic extractive desulfurization. FCC gasoline hydrotreaters operate at lower temperatures and pressures than FCC feed hydrotreating which further reduces the capital and operating costs associated with this type of desulfurization equipment. For a medium to large refinery, the capital costs would be on the order of \$50 million for a conventional hydrotreater.

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One drawback of this desulfurization methodology is that the octane value and/or some of the gasoline yield may be lost depending on the process used for desulfurization. Octane loss can occur by the saturation of high octane olefins which are produced by the FCC unit. Most of the olefins are contained in the lighter fraction of FCC naphtha. With increased olefin saturation comes increased hydrogen consumed. There can be a loss in the gasoline yield caused by mild cracking which breaks some of the gasoline components into smaller fractions which are too light for blending into gasoline. If there is octane loss, it must be made up by additional octane production by other units in the refinery or by oxygenate addition, and any volume loss can be made up by additional throughput to gasoline producing units, or also by oxygenate addition.

The loss of octane and gasoline yield caused by FCC gasoline hydrotreating is much lower by technologies which were recently developed. These processes preserve much of the octane and gasoline yield because they were designed for treating gasoline blendstocks. Octane is preserved because their catalysts are specially designed to either avoid saturating olefins, or if the process does saturate olefins, it causes other reactions to occur which improves the octane of the gasoline lost through desulfurization. These processes may also operate at less severe conditions than conventional hydrotreaters which preserves yield compared to conventional hydrotreating processes. The less severe conditions lowers the capital and operating costs for this process. Typical capital cost for these newer desulfurization technologies ranges from \$20 to \$40 million for a medium to large sized refinery. The lower operating costs arise out of the reduced utility requirements (e.g., process heat, electricity), octane losses and hydrogen consumption. For example, because these processes are less severe, there is much less or no saturation of olefins, which means that there is much less hydrogen used. Less olefin saturation also translates into less octane loss which would otherwise have to be made up by octane boosting processing units in the refinery.

The lower capital and operating costs of these newer FCC gasoline hydrotreaters are important incentives for refiners to choose this desulfurization methodology over conventional FCC gasoline or FCC feed hydrotreating. That some refiners would use this newer desulfurization technology is reinforced by conversations with refiners and licensors of hydrotreating hardware. For this reason, we are assuming that many refiners will choose to use the more recently developed FCC gasoline hydrotreating technologies for meeting the gasoline sulfur standard.

For the NPRM we presumed that refiners would choose either of two of the more improved FCC gasoline desulfurization processes, CDTech or Mobil Oil Octgain 220. However, we received a number of comments from the oil industry that they generally require that refining processes be commercially demonstrated, for at least two years, before choosing to use these technologies. Since the CDTech and Mobil Oil have not been commercially demonstrated that length of time yet, we expanded our list of technologies upon which we are basing our rule to currently proven FCC gasoline desulfurization technologies. Furthermore, we learned of another class of FCC gasoline desulfurization technologies which are now commercially available.

These newest desulfurization technologies work by adsorption and work more efficiently than hydrotreating desulfurization technologies. We are including these technologies in our analysis as well.

i. Proven Desulfurization Technologies

We know of three commercially proven FCC gasoline desulfurization technologies. These are Mobil Oil Octgain 125, Exxon Scanfining, and IFP Prime G. These are all fixed bed desulfurization technologies, so they function similar to each other. These processes are called fixed bed because the catalyst resides in a fixed bed reactor.¹³ The high sulfur gasoline blendstock is heated to a high temperature (on the order of 600 degrees Fahrenheit) and pumped to a high pressure, to maintain the stream as a liquid, and is combined with hydrogen before it enters the reactor. The reactions occur over the bed of the catalyst. While the petroleum is in contact with the catalyst in the reaction vessel, the sulfur is removed from the petroleum compounds and is converted to hydrogen sulfide. Also, depending on the process, some, most or all of the olefin compounds which are present in the cracked stream are saturated which increases the amount of octane lost and hydrogen consumed. The difference between these and conventional hydrotreating processes is that these technologies have a way for either minimizing the loss in octane or compensating for it, either by minimizing the loss of olefins, or by recovering the lost octane through octane producing reactions. The catalyst may cause yield loss through cracking of some of the petroleum compounds. After the reactor, the gaseous compounds, which include unreacted hydrogen, hydrogen sulfide, and any light end petroleum compounds which may have been produced in the reactor by cracking reactions, are separated from the liquid compounds. The hydrogen sulfide must be stripped out from the other compounds and then converted to elemental sulfur in a separate sulfur recovery unit, and the recovered sulfur is then sold. If there is enough hydrogen and it can be economically recovered, it is separated from the remaining hydrocarbon stream and recycled. Otherwise, it would probably be burned with the light hydrocarbons as fuel gas.

Each of these commercially proven desulfurization technologies are a little different. The Octgain 125 process saturates all the olefins, but recovers the lost octane through isomerization and alkylation.¹⁴ It needs to be run at fairly severe conditions for it to recover octane, so this process is more appropriate for refiners with higher sulfur levels which requires severe hydrotreating to reach the sulfur target. While octane loss can be eliminated with the proper operating conditions, yield loss can be significant. It has been commercially demonstrated at Mobil's refinery in Joliet, Illinois.

Exxon's Scanfining process preserves octane by saturating very few olefins, however, at severe operating conditions for higher levels of desulfurization, octane loss can be high. The Scanfining catalyst causes very little yield loss. This process has been demonstrated for a total of over 4 years in two of Exxon's refineries.¹⁵

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IFP's (Institut Français du Pétrole) Prime G desulfurization process largely preserves olefins as its strategy for diminishing octane loss.^{16 17} Like Scafining, Prime G is less severe and cracks the petroleum compounds less resulting in less yield loss. Prime G has been commercially demonstrated for over 7 years in two U.S. refineries, and in an Asian refinery.

ii. Improved Gasoline Desulfurization Technology

Consistent with the NPRM, we are placing CDTech and Mobil Oil Octgain 220 processes in the same category called improved desulfurization technologies, and these technologies have not yet had significant commercial experience. Mobil Octgain will be discussed first since the process is similar to the commercially proven hydrotreating technologies discussed above. Like the commercially proven desulfurization technologies, the Mobil 220 process uses a fixed bed for its catalyst.¹⁸ Octgain 220 preserves most of the olefins and recovers lost octane through isomerization reactions.^{19 20} The less severe operating conditions also causes less yield loss, as the conditions are less favorable for causing cracking of the larger petroleum compounds to smaller compounds. For high levels of desulfurization, yield and octane loss increase significantly for this process so Mobil recommends that refiners use the 125 process for these desulfurization cases. Mobil loaded the 220 catalyst into their Joliet hydrotreater during March of 1999, so the process has some commercial experience. In addition, Mobil Oil has signed a license agreement with a refinery outside the U.S., so another Octgain unit will be installed soon.

The CDTECH process is significantly different from either conventional hydrotreating or Octgain, and it is a little more complex to describe. The CDTECH process utilizes catalytic distillation.^{21 22 23} Catalytic distillation is a technology which has been applied for a number of different purposes. CDTECH is currently licensing the technology to produce MTBE and selective hydrogenation processes. Based on their experience and success with that process, they applied the same technology to desulfurizing gasoline. As the name implies, distillation and desulfurization, via a catalyst, take place in the same vessel. This design feature may save the need to add a separate distillation column in some refineries. All refineries have a distillation column after the FCC unit (called the main fractionation column) which separates the gasoline from the most volatile components (such as liquid petroleum gases), the distillate or diesel (light cycle oil), and the heavy ends or residual oil. However, if a refiner only wishes to treat a portion of the FCC gasoline, then he may have to add a second distillation column to be able to separate off the portion of the FCC gasoline which he wishes not to treat. With the CDTech process, the refiner can choose to treat the entire pool or a portion of the pool, but choosing to treat a part of the pool can be an option in how the CDTech hardware is applied, thus negating any need for an additional distillation column.

The most important portion of the CDTech desulfurization process is a set of two distillation columns loaded with desulfurization catalyst in a packed structure. The first vessel, called CDHydro, treats the lighter compounds of FCC gasoline and separates the heavier portion

of the FCC gasoline for treatment in the second column. The second column, called CDHDS, removes the sulfur from the heavier compounds of FCC gasoline. All of the FCC gasoline is fed to the CDHydro column. The 5 and 6 carbon petroleum compounds boil off and head up through the catalyst mounted in the column, along with hydrogen which is also injected in the bottom of the column. The reactions in this column are unique in that the sulfur in the column are not hydrotreated to hydrogen sulfide, but they instead are reacted with dienes in the feed to form thioethers. Their higher boiling temperature causes the thioethers to fall to the bottom of the column. They join the heavier petroleum compounds at the bottom of the column and are sent to the CDHDS column. Because the pressure and temperature of the first column is much lower than conventional hydrotreating, saturation of olefins is reduced to very low levels (according to CDTECH, the saturation which does occur is desirable to eliminate diolefins). Thus, little excess hydrogen is consumed. An option for the refiner is to put in an additional catalyst section in the CDHydro column to increase octane. This octane enhancing catalyst isomerizes some of the olefins which increases the octane of this stream by about three octane numbers, and few of the olefins are saturated to degrade this octane gain.

The seven-carbon and heavier petroleum compounds leave the bottom of the CDHydro unit and are fed into the CDHDS column. There, the heavier compounds head down the column, and the lighter compounds head up. Both sections of the CDHDS column have catalyst loaded into them which serve as hydrotreating reaction zones. Similar to how hydrogen is fed to the CDHydro column, hydrogen is fed to the bottom of the CDHDS column.

The temperature and pressure of the CDTech process columns are lower than fixed bed hydrotreating processes, particularly in the upper section of the distillation column, which is where most of the olefins end up. These operating conditions minimize yield and octane loss. While the CDTech process is very different from conventional hydrotreating, the catalyst used for removing the sulfur compounds is the same. Thus, if concerned about the reliability of the process, refiners can look at the track record of the catalyst in conventional hydrotreating to get an indication of its expected life, and then adjust that expectation based on the milder conditions involved. One important different between the CDTech process and conventional hydrotreating is that CDTech mounts its catalyst in a unique support system, while conventional catalyst is simply dumped into the fixed bed reactor. Although the CDTech desulfurization process is different from conventional hydrotreating processes, the use of a distillation column as the basis for the process is very familiar to refiners. Every refinery has distillation in its refinery, thus, refiners are very skilled in its application.

CDTech has numerous CDHydro units in operation, but CDHDS units have not yet been installed in refineries. Thus, one portion of the CDTech process is commercially proven, while the other portion is not. A CDHDS unit is expected to be operational in the Motiva refinery in Port Arthur, Texas starting March of 2000. Additionally, a combined CDHydro/HDS unit is expected to be operational in North America in October of 2000, and another license agreement has been signed for an installation in Europe. An installation of an HDS unit is planned for the

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Transamerican refinery in Louisiana, however, that refinery is currently shutdown and the startup date of the refinery and the planned CDHDS unit is unclear.

The relative cost of the improved desulfurization technologies and the commercially proven technologies depends on the specific situation faced by a refiner. For most refiners, the more recent, improved desulfurization technologies are projected to be less expensive. However, as we point out above, Mobil Oil recommends that the Octgain 125 process be used for treating the FCC naphtha from heavy, high sulfur crude oils. In our analysis, we are estimating the desulfurization cost of average refineries meeting the gasoline sulfur standard, and Mobil Oil would probably recommend that their Octgain 220 process be used for this application. However, Scanfining and Prime G processes are well suited desulfurizing technologies for average refineries as well. Thus, when we use costs developed for improved technologies, these costs could be representative for some of the proven technologies as well.

iii. Adsorption Desulfurization Technologies

Black and Veatch Pritchard Inc. and Phillips Petroleum Co. have announced the commercial availability of adsorption desulfurization technologies (i.e., they are prepared to design and license this technology to refiners). We believe that similar adsorption technologies may be available soon from UOP and a major refiner as well. These technologies use the chemical process of adsorption, instead of hydrotreating, as the principal methodology for the removal of sulfur from gasoline. Adsorption has the benefit of operating at much lower pressure and temperatures, which lowers operating costs, and potentially can lower capital costs as well. Each of these desulfurization processes operates differently.

The Black and Veatch process, named IRVAD, adsorbs heteroatom-containing petroleum compounds, which are sulfur, nitrogen and oxygen containing petroleum compounds, onto their adsorption catalyst.²⁴ The catalyst is alumina-based and manufactured by Alcoa Industrial Chemicals. The catalyst is fluidized and continuously removed and regenerated, using hydrogen, in a second column. The regenerated catalyst is then recycled back into the reactor vessel at the rate which it is being removed. In the regeneration column, the adsorbed heteroatom containing petroleum compounds, which is about 4 percent of the petroleum stream being treated, are removed from the catalyst. Since the hydrogen used in the regeneration column is for scavenging the petroleum compounds off of the catalyst and it is not reacting with the petroleum, hydrogen loss is considered by Black and Veatch to be negligible. According to Black and Veatch process operations information, the treated FCC gasoline is 2 octane numbers higher than the untreated FCC gasoline.

This high sulfur stream, which contains about 1 percent by weight of sulfur (10,000 ppm), must then be treated for reblending with gasoline. This stream cannot just be blended to offroad diesel since it contains many volatile petroleum compounds. Black and Veatch surmises that

most refiners would treat the stream in an existing diesel hydrotreater. After hydrotreating, the gasoline substream, which is now blended in with desulfurized diesel, would have to be separated either by the existing stripping column which hydrotreating processes have for separating the light ends produced in these facilities, or in a splitting column which may already be installed after the hydrotreater. If the stripping column is insufficient for the volume of gasoline which would have to be hydrotreated, and there is not an existing splitting column, then a splitting column would have to be added, or the stripping section would have to be enlarged. At the time that this document was being drafted, Black and Veatch had not yet signed a license agreement to install one of their units, although two refiners who own small refineries have given Black and Veatch verbal agreements that they will install IRVAD units in their refineries.

The adsorption process by Phillips, called S-Zorb, is similar to the Black and Veatch process in that two separate columns are needed and the catalyst is constantly moving from the reactor vessel to the regeneration column, and back again.²⁵ However, beyond that, the processes are very different. The untreated FCC naphtha and hydrogen are fed to the reaction vessel where the Phillips catalyst adsorbs the sulfur-containing petroleum compounds onto the catalyst. However, the catalyst also catalytically removes the sulfur from the petroleum compound so the petroleum compound which contained the sulfur never leaves the reaction vessel. Instead, the catalyst which begins to accumulate the removed sulfur, is transferred over to the regeneration column on a continual basis where the sulfur is removed from the catalyst using hydrogen as the scavenging compound. Then the hydrogen disulfide is converted to sulfur dioxide and sent to the sulfur recovery unit. Since, the petroleum compounds are desulfurized in the main reactor, there is no need to hydrotreat any high sulfur stream. However, because the process still relies upon catalytic processing in the presence of hydrogen, there is some saturation of olefins, with a commensurate reduction in octane. Currently, there are no S-Zorb units operating, however, Phillips is working rapidly to install a 6000 barrel per day unit at its Borger, Texas refinery, and plans to have it operating by the first quarter of 2001.

5. Expected Desulfurization Technology to be Used by Refiners

With the promulgation of the Federal sulfur control program, which begins to phase-in in 2004, refiners which produce gasoline would have to meet the standard to be able to continue participating in the U.S. gasoline market. As stated above, most refiners will have to install capital to meet the sulfur standard. Arguably, refiners would try to minimize the cost to their business. As stated above, the adsorption gasoline desulfurization technologies seem to be the lowest cost technologies based on our analysis of average refineries in each PADD, followed by the improved desulfurization technologies, such as CDTECH and Mobil Oil Octgain. However, several refiners have shared with EPA that they may be hesitant to use these improved, but recently developed technologies for gasoline desulfurization. They claim that until the technologies have been installed in one or more refineries and operated for a while, that there will continue to be a significant measure of uncertainty. This uncertainty could tip the balance

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away from using the lower cost adsorption and improved desulfurization technologies, to applying proven desulfurization technologies.

While there is a concern now on the part of some refiners about using the adsorption and improved, but not commercially tested desulfurization technologies, we believe that much of this concern will dissipate in the near future. All these processes are expected to be operating commercially in the next two years. Mobil Oil has already installed its Octgain 220 catalyst in the hydrotreater at its Joliet, Illinois refinery and is accruing commercial experience with that technology. CDTech has years of accumulated service with its CDHydro unit, but not with the CDHDS unit. The CDHDS unit and the adsorption technologies are expected to be installed in refineries in the year 2000 and 2001.

We have clear examples specific to these technologies that refiners do not need to observe a certain technology operating in a refinery before they will choose to use that technology. For example, no CDHDS units, nor complete CDHydro/CDHDS units, are up and operating, however, a handful of refiners have committed to installing the process in their refineries. Thus, these refiners have been willing to commit to that technology without observing it operating commercially in a refinery. We believe that it may be more difficult to commit to the adsorption technologies as easily, as they are somewhat different from conventional desulfurization technologies. For developing the cost of the desulfurization program, we need to project the types of desulfurization units which will be installed during the years that the gasoline sulfur program is phased-in. Our projections are summarized below in Table IV-15.

Table IV-15. Projected Use of Desulfurization Technology Types by Refiners During the Phase-in Period

<i>Year</i>	<i>Mix of Technology Types Used</i>
2004	1/2 Proven, 1/2 Improved
2005	3/4 Improved, 1/4 Adsorbent
2006	1/2 Improved, 1/2 Adsorbent
2007 & 2008	1/4 Improved, 3/4 Adsorbent

Prior to 2004, we project that new desulfurization units will fall into two broad categories: early units being installed by refiners who desire to generate credits and possibly use low sulfur as a marketing factor and demonstration units. We project that the former will primarily utilize proven technology (90 percent proven, 10 percent improved). On the other hand, the demonstration units will all utilize improved or adsorbent technology, as there is no need to demonstrate the proven technology. On a volumetric basis, we project a breakdown of

50 percent proven, 25 percent improved, and 25 percent adsorbent.

6. Feasibility for a Low Gasoline Sulfur Standard in 2004

The final gasoline sulfur control program provides a full four years before the first sulfur standard must be met starting on January 1, 2004. As discussed below, not all refiners will have to modify their operations on this date. Thus, more than four years leadtime is available for many refiners (i.e., those with low current sulfur levels). This is consistent with requests received from API and NPRA, as well as from a number of refiners, in their comments to the proposal, that at least four years be provided prior to the start date of the program.

The following table breaks down the steps involved in constructing new refining equipment and our projection of the time necessary for each step and the entire process. The reader is also referred to the Draft RIA for some additional detail in the development of these estimates.

Table IV-16. Leadtime Required Between Promulgation of the Final Rule and Implementation of the Gasoline Sulfur Standard (years)

	<i>Naphtha/Gasoline Hydrotreating</i>		<i>More Major Refinery Modification (e.g., FCC Feed Hydrotreating)</i>	
	<i>Time for Individual Step</i>	<i>Cumulative Time</i>	<i>Time for Individual Step</i>	<i>Cumulative Time</i>
Scoping Studies	0.5-1.0*	0.5	0.5-1.0*	0.5
Process Design	0.5	1.0	0.5-0.75	1.0-1.25
Permitting	0.25-1.0	1.25-2.0	0.25-1.0	1.25-2.0
Detailed Engineering	0.5-0.75	1.5-2.25	0.5-1.0	1.5-2.25
Field Construction	0.75-1.0	2.0-3.0	1.0-1.5	2.5-3.5
Start-up/Shakedown	0.25	2.25-3.25	0.25	2.75-3.75

* Can begin before FRM

Scoping and screening studies refer to the process whereby refiners investigate various approaches to sulfur control. These studies involve discussions with firms which supply gasoline desulfurization and other refining technology, as well as studies by the refiner to assess the economic impacts of various approaches to meeting the sulfur standard. In the case of gasoline desulfurization, a refiner would likely send samples of their FCC gasoline to the firms marketing

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gasoline desulfurization technology to determine how well each technology removed the sulfur from that particular type of FCC gasoline (e.g., sulfur removal efficiency, octane and yield loss, hydrogen consumption, etc.).

Based on discussions with both refiners and technology providers, it is clear that many refiners have already been conducting these studies for at least a year. We believe that by the time of the final rule, refiners will already have a very good idea of the performance and economics of the various gasoline desulfurization technologies at the pilot plant level. For example, refiners have been sending samples of their FCC naphtha to the vendors of desulfurization technology for some time to determine exactly how well each technology will perform in their specific refinery. Some time will be required to process the details of the final rule. More importantly, however, is that many of the new gasoline desulfurization technologies will not have been demonstrated in actual refinery applications by the end of this year. Refiners naturally desire as much demonstrated experience with any new technology as possible prior to investing significant amounts of capital in these technologies. Thus, the fact that less than four years are actually needed to design and build gasoline desulfurization equipment once the technology is selected and some refiners do not need this equipment until 2005 or beyond allows refiners to observe the performance of these new, potentially lower cost technologies and make a more informed selection in a year or two. We believe that at a minimum, refiners should have 6 months after the final rule to assess their situation with respect to the final sulfur control program and select their technological solution.

The time required for process design will depend on the extent of the refinery modifications planned. We expect that the great majority of refiners will hydrotreat their FCC gasoline. If no existing equipment is used, this primarily involves building the hydrotreater and its associated equipment (distillation columns, furnaces, pumps, compressors). The refiner would also require a source of a hydrogen for the desulfurization unit. This could come from hydrogen already being generated in the refinery, or from an outside source. In the extreme, the refiner would have to build its own hydrogen plant. Finally, the refiner will have to ensure that the hydrogen sulfide being generated from the desulfurization equipment can be processed in the refinery's existing sulfur recovery plant. Given the small amount of sulfur being removed from gasoline compared to the amount of sulfur already being processed in the refinery, this is likely to be possible with little change to the sulfur recovery plant. However, some expansion could be required.

All of this equipment is already common to refineries. Aside from the new adsorption technologies, all gasoline desulfurization units are very similar to existing distillation columns or gasoline and diesel fuel hydrotreaters already being used in essentially every refinery. Hydrogen plants are widely used throughout the refining and chemical industries and can be purchased from vendors as basically stand alone units. The same is true for sulfur recovery plants. Also, design and construction time has been reduced by up to 40 percent between 1991 and 1996 alone by computerized design and improving construction scheduling using state of the art methods.²⁶

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For example, CDTECH estimates that 10 - 12 weeks are needed for the basic process design of their equipment. Discussions with other contractors have indicated that 4-5 months is usually more than sufficient to complete the process design.

It is possible that some refiners might decide to implement more major changes to the refinery, such as adding a FCC feed hydrotreater. This equipment is more unique to each refinery and could require some additional time to design. However, this equipment would significantly reduce a variety of emissions from the FCC unit, particularly SO_x and toxics. However, FCC hydrotreating can increase NO_x emissions relative to naphtha hydrotreating due to processing more hydrocarbons and the greater temperature and pressure involved. The emission reductions should ease permitting and compliance with future MACT standards for toxics, while the NO_x emission increase would have to be addressed in ozone nonattainment areas subject to NO_x offsets. We have allocated up to 3 months more for the process design of these more major modifications.

Regarding permitting, EPA has held a number of discussions with state/local permitting agencies, environmental organizations and refiners. EPA is committed to streamlining the process of obtaining permits. One step in this process would be to identify soon after the final rule the technologies that EPA believes would constitute Best Available Control Technology (BACT) and the Lowest Achievable Emission Rate (LAER). This would inform both states and refiners of the types of refinery emission control technology EPA believes would meet the BACT and LAER requirements. The lower limit of 3 months is typical for obtaining a minor source permit. States such as Texas typically issue permits in four months on average, including major NSR permits. One year for a permit would represent a very protracted process which should be avoidable if refineries are working closely with the states to resolve any issues that may arise during the permitting process. Nonetheless, this time period was included above in order to identify the worse case situation which may occur. EPA's permit streamlining approaches should provide opportunities to shorten this time period even further.

Based on discussions with contractors, design and construction of naphtha hydrotreaters typically requires about 18 to 20 months, while about two years is required for more major equipment like FCC feed hydrotreaters. If all refiners attempted to construct their new equipment at the same time, limited capacity of vendors who manufacture the pressure vessels and compressors could extend these times to 24-30 and 36 months. However, as described in the next section, we have explicitly designed the sulfur control program to spread out construction. Thus, the manufacturing capability of these equipment vendors should not be over-taxed.

Several different fuel programs already in place suggest that a stringent gasoline desulfurization program can be phased-in in four or less years. The California sulfur control program which was promulgated in June of 1975, started to phase in only six months after promulgation, and was fully phased in 4½ years later.²⁷ Similarly, the Phase II California Reformulated Gasoline Program was promulgated in November 1991 and took effect about 4½

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years after promulgation.²⁸ However, in addition to a stringent sulfur control standard, refiners also had to meet stringent controls for aromatics, olefins, Reid vapor pressure, and distillation index. Also, because the refining industry already has extensive experience with meeting the California low sulfur requirement, it likely could meet a similar standard sooner.

The On-Road diesel sulfur rulemaking provides an example of refiners meeting a much shorter compliance period. Refiners nationwide met the on-highway low sulfur diesel standards in three years time; since the rulemaking was promulgated August 1990 and took effect October 1993.²⁹ That rulemaking required refiners to reduce diesel sulfur levels from over 2000 ppm down to under 500 ppm. Diesel hydrotreaters are fixed bed hydrotreaters which, as described above, are essentially the same design as fixed bed gasoline desulfurization units, such as Octgain. Refiners' volume of onroad diesel fuel is generally less than their FCC gasoline volume. However, leadtime is generally not a strong function of unit capacity, at least for capacity differences of this magnitude.

For the Reformulated Gasoline Program, EPA proposed to give refiners 4 years to meet the Complex Model requirements of the Reformulated Gasoline program. We felt that 4 years was necessary so that refines could take time to understand how to most cost-effectively use the Complex Model, and to install whatever capital which needed to be installed. However, this rulemaking specifies a single specification and not require the use of a complex emissions model.

Small refiners may need more time to comply with a sulfur control program. Small refiners generally have a more difficult time obtaining funding for capital projects, and must plan further in advance of when the funds are needed. We contracted a study of the refining industry which included assessing the time required for small refiners to obtain loans for capital investments. The simple survey revealed that small refiners would need two to three months longer than large refiners to obtain funding. If small refiners are forced to or prefer to seek funding through public means, such as through bond sales, then the time to obtain funding could be longer yet, by up to one third longer.³⁰ In addition, because of the more limited engineering expertise of many small refiners, the design and construction process for these refineries is relatively more difficult and time consuming. We also think that the contractors which design and install refinery processing units will likely focus first on completing the more expensive upgrade projects for large refiners. Thus the design and construction of desulfurization hardware in the refinery would take longer as well. For this and other economic reasons, we are proposing to delay the implementation of the low sulfur program for small refiners. Under one set of provisions, the smallest refiners will be given until 2008 to meet the 30 ppm sulfur standard. Under another set of provisions, refiners supplying fuel to a number of western states will be given until 2007 to meet the 30 ppm standard. This provision most directly affects the relatively small refineries located in these western states. This additional leadtime should provide not only enough time for these small refiners to construct equipment, but to also allow these refiners more time to select the most advantageous desulfurization technology. This additional time for technology selection will help to compensate for the diseconomy of scale inherent with adding

equipment to a small refinery.

7. Phase In of Compliance with the Proposed Sulfur Standards and Early Credit Generation

As stated earlier in this chapter, the sulfur content of gasoline in 1998 averaged about 268 ppm, well above the eventual refinery average standard of 30 ppm. The vast majority of the sulfur in gasoline comes from a single gasoline blending component, FCC or cat naphtha. As projected above, for most refiners, removing enough sulfur from FCC naphtha to meet a 30 ppm standard on average will require the construction of a naphtha desulfurization unit.

There are two reasons to evaluate the timing of the construction of these desulfurization units. One, the type of desulfurization technology employed must be determined at the beginning of the design and construction process. A desulfurization unit whose design and construction begins prior to the time when a specific desulfurization technology is deemed to be commercially proven and ready for broad application will generally not be available for use in that specific refinery. As discussed above, we have identified three groups of desulfurization technology ranging from those already commercially proven to those which will generally not be available for use (not design and construction) until 2005. Therefore, if the applicable gasoline sulfur standards require a refinery to install a hydrotreating unit in 2004, a refiner may consider its options for desulfurization technology to be more limited than if he could delay the installation until 2005 or later.

The second reason to project the timing of new desulfurization units is to evaluate the ability of the design and construction industry to fulfill the needs of the refining industry. Here, the type of unit is less important (though not irrelevant), because all of the technologies use pressure vessels of some type, compressors and process heaters. The vendors which manufacture these items are limited in number, so the more refiners ordering this equipment at the same time, the longer the leadtime for delivery.

Projecting the timing of this new equipment consisted of a two step process. In the first step, EPA evaluated the sulfur levels of gasoline certified in 1997 and 1998 to estimate each refinery's average gasoline sulfur level in these two years. This was done separately for RFG and CG, as these two types of fuels are certified separately to different quality standards. There are 126 refineries in the U.S. that produced gasoline in 1998. This total includes 12 refineries located in California, which produce gasoline primarily for the state of California. As only a small portion of the gasoline produced by California refineries will be affected by this regulation, these refineries will be addressed separately below. The total of 126 also includes 14 refineries which are located in the 6 states which are included in the temporary geographical phase-in program and 17 refineries which fall under the small refiner provisions. These two sets of refineries are also addressed separately below.

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The following table shows the number of refineries whose average sulfur levels fall into various ranges.

Table IV-17. Number of U.S. Refineries with 1998 Sulfur Averages Falling Into the Specified Range of Sulfur Content (ppm)

<i>Sulfur Range</i>	≤ 100	101-200	201-300	301-400	401-500	>500
Number of Refineries	22	29	28	12	5	14

As can be seen, refinery's current sulfur levels vary dramatically. This causes some refineries to deeply desulfurize FCC naphtha earlier under EPA's sulfur control program than others.

The current national average pool sulfur levels were 293 ppm and 207 ppm for CG and RFG, respectively, based on the CG and RFG batch certification reports. This is considerably lower than the 1997 CG and RFG sulfur levels of 314 and 282, respectively. This significant reduction in gasoline sulfur is likely due to the mandatory use of the Complex Model in the certification of both CG and RFG beginning in 1998. Prior to 1998, the Simple Model was used to certify RFG and sulfur levels were simply capped at 1990 levels. Prior to 1998, CG sulfur levels could be as much as 25 percent higher than 1990 levels. The Phase II RFG specifications begin in 2000. EPA projects that RFG sulfur levels will average roughly 150 ppm during the summer months. In their comments to the Tier 2/sulfur rule, several refiners and refining organizations indicated that refiners could meet the sulfur-related portion of the Phase II RFG requirements without reducing their refinery average sulfur levels. They indicated that they could shift sulfur from RFG to CG during the summer and reverse this shift during the winter. As noted above, 1998 RFG sulfur levels are only 57 ppm above this target. No further reduction in pool sulfur is expected to occur with Phase II RFG, only shifts in sulfur between CG and RFG

The second step in this process was to develop and apply criteria which indicate which refineries must install and apply desulfurization equipment under various sulfur standards. In any particular calendar year, refiners have to comply with up to three specifications: a per gallon standard, a corporate average standard and a refinery average standard. The first applies to every batch of gasoline introduced into the market. The second can be met by averaging across refineries within a corporation, and also through the trading of allotments across refiners. Thus, in essence, assuming allotments are actively traded, the corporate average standard essentially becomes a national average standard. Finally, the refinery average standard can be met on average by a refinery and through the trading of credits generated relative to this standard. In 2005 and 2006, the refinery average standard can also be met through the trading of early sulfur reduction credits (i.e., reductions in sulfur relative to a refinery's baseline generated prior to

2004). Criteria were developed to represent each of these three specifications.

The first set of criteria apply to a refinery's ability to comply with a per gallon cap. For sulfur levels of 100 ppm or more, EPA projects that a refinery will produce gasoline with an average sulfur level about two-thirds of the level of the per gallon cap. For example, a refinery is expected to average 200 ppm sulfur under a 300 ppm cap. There is no need to project an average sulfur level under the 80 ppm cap, as compliance with the average standard of 30 ppm should be sufficient for compliance with the cap (temporary equipment disruptions aside).

As indicated above, the corporate average standards are essentially national average standards, intended to ensure that, on average, the national pool of gasoline does not exceed certain sulfur levels. Thus, the primary criterion indicating compliance is the national average sulfur level. Again assuming actively traded allotments, the national average sulfur level need be just below the corporate average standard. However, it is unlikely that every refiner would market every allotment generated relative to the standard. Refiners will likely keep some allotments back from the market in order to provide themselves with a compliance cushion towards the standard. Also, there could be some inefficiencies in the market. For example, some refiners may be looking for allotments prior to other refiners deciding that they have excess allotments to sell. Later, when allotments become available, potential buyers have already decided to comply with the standards without the need for allotments. Thus, to be conservative, we projected that refiners would have the capability of producing fuel with a national average sulfur level 30 ppm below the applicable corporate average standard. This translates into the capability to produce national average sulfur levels of 90 ppm in 2004 and 60 ppm in 2005.⁴

Finally, criteria were developed to represent compliance with the refinery average standard of 30 ppm. In 2005, we assumed that refiners would use early credits to allow them to produce fuel complying with the corporate average standard of 90 ppm. In 2006 and later, we assumed that the refinery would have to average 30 ppm sulfur.

The third and final step was to determine when a refinery had to build a desulfurization unit in order to comply with one of the above criteria. First, when complying with the temporary cap of 300 ppm, as indicated above, a refinery is presumed to average 200 ppm sulfur or less.

⁴ While refiners are projected to be able to produce gasoline at these levels, this does not necessarily mean that these sulfur levels will be achieved. We expect that most refiners will design their refineries to be capable of producing 30 ppm sulfur gasoline, as this is the long-term standard. However, prior to 2006, some refiners may utilize their equipment to produce gasoline at 30 ppm, while others will find that they can comply with the interim standards while using this equipment to produce gasoline with higher sulfur levels. For example, a refiner may produce 30 ppm gasoline for a portion of the year in order to generate allotments in case of operational difficulties later in the year. However, as the year progresses, these allotments will build up and the likelihood of a disruption will decrease. Therefore, they could operate this equipment at a lower sulfur removal efficiency in order to reduce costs.

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We project that a refinery could reduce its maximum sulfur level (i.e., that which determines compliance with the per gallon cap) by 20 percent for a year or so in order to delay construction of new equipment. Therefore, refineries with average sulfur levels of 250 or less are projected to be able to delay construction of new desulfurization units under the 300 ppm cap. In addition, three refiners informed EPA that they had refineries with sulfur averages above 250 ppm which could meet the 300 ppm cap without major construction due to more unique circumstances (excess equipment on site, existing excess hydrodesulfurization capacity, etc.)

This 20 percent sulfur reduction due to operational modifications is based on an assessment of the capability of a number of sulfur reducing techniques available to refiners. First, refineries with FCC feed hydrotreating can usually increase the severity of their units to remove more sulfur from the FCC naphtha. Second, many refiners can switch or shift to a lower sulfur crude oil. Third, refiners can route some of their FCC naphtha to their reformer hydrotreater and reformer. Fourth, refiners can change their FCC catalyst to one which reduces the amount of sulfur in FCC naphtha. (Grace makes such a catalyst.) Finally, refiners can shift the heaviest (and most sulfur laden) portion of their FCC naphtha to the distillate pool. The cost associated with each of these techniques generally increases as one progresses down the list. The cost which a refiner would be willing to pay will depend on the value of delaying the selection and construction of new desulfurization equipment.

With regard to the final 30 ppm refinery average standard, we project that a refinery will need to construct a new desulfurization unit if its current average is greater than 50 ppm. As discussed in Section 4 above, refiners that currently have such a low sulfur level probably do not have an FCC unit, hydrotreat the FCC feed, or utilize low sulfur crude. In this situation, the refiner should be able to reduce their sulfur further through operational changes and avoid major capital investment.

The same basic criteria were applied to those refineries which are covered by the temporary geographical phase-in program and the small refiner provisions, with the exception that the standards which these refineries must meet differ to some degree from those which are generally applicable. For example, under the temporary geographical phase-in program, refiners must meet a 300 ppm cap and a 150 ppm refinery average standard in 2004. Since credits or allotments can be purchased and used in meeting the 150 ppm standard, the 300 ppm cap is the primary controlling standard. As discussed above, refineries currently with an average sulfur level of more than 250 ppm are projected to install a desulfurization unit in order to meet the 300 ppm cap, except for three refineries, as noted previously. These standards apply unchanged until 2007, when the 30 ppm average standard and 80 ppm cap take effect. As projected above for other refineries, all refineries with a current average sulfur level above 50 ppm are projected to install a desulfurization unit in order to meet the 2007 standards.

Refineries covered under the small refiner provisions which currently have an average sulfur level of 200 ppm or less only need to maintain that level until 2008. Those with current

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average sulfur levels between 200 and 300 ppm will have to modestly reduce their sulfur levels, while those with higher sulfur levels will have to reduce their sulfur levels more significantly. Only five small refiners currently average more than 300 ppm sulfur. Given that these refiners will not have to meet the 30 ppm standard until 2008 (four years after the date of the initial standard), these five refiners have a significant incentive to delay the installation of naphtha desulfurization equipment until that time. Thus, we project that they will modify their refinery operations to the fullest degree possible to reduce sulfur and avoid constructing their final desulfurization equipment. This could involve the operational modifications described above. It could also involve more modest investment in new equipment, which would reduce sulfur modestly and immediately, while being useful in the long term, as well. An example of this would be the installation of a distillation column to separate light and heavy FCC gasoline and a Merox unit to remove sulfur from the light FCC naphtha. Instead of projecting that all five will require a naphtha desulfurization unit in 2004, we only project that two will require units.

Regarding California refiners, we analyzed the gasoline sold by these refiners outside of California in 1997 and 1998. We also compared the volume of fuel sold outside of California to that sold inside of California by each refiner. With two exceptions, the non-California fuel produced by California refiners contains 50 ppm sulfur or less and represents a small fraction of total gasoline production. Thus, compliance with the Federal sulfur program should not require major new equipment at 10 of the 12 California refineries marketing gasoline outside of the state. One of the two remaining refineries certified non-California fuel in 1998, but did not do so in 1997. The 1998 non-California fuel averaged 91 ppm and represented 10-15 percent of their total gasoline production. Assuming that their California gasoline was at 30 ppm sulfur or lower, this refinery's overall average sulfur level was 36-39 ppm, well under our 50 ppm criterion mentioned above. Thus, this refinery should not require an additional desulfurization unit. The one remaining refinery appears to be selling a significant fraction of its fuel outside of California at an average sulfur level of about 150 ppm in 1998. We project that this refinery will add a desulfurization unit in 2006 in order to comply with the Federal sulfur control program.

We applied these criteria to the each refinery's 1997 and 1998 two-year average sulfur levels and projected both the number of new desulfurization units which would be required each year, as well as the national average sulfur level. In determining the national average sulfur level, we assumed that refineries with new desulfurization units would operate at 30 ppm sulfur on average year round. The results are shown in Table IV-18 below.

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Table IV-18. Number of New Desulfurization Units Operating by January 1 of Indicated Year and National Pool Average Sulfur Levels Under the Final Sulfur Standards

	<i>2003 and Earlier</i>	<i>2004</i>	<i>2005</i>	<i>2006</i>	<i>2007</i>	<i>2008</i>
New Units	7-10	37-40	6	23-26	9	9
Sulfur (ppm)	---	67	60	31	30	30

As shown in Table IV-16, 7-10 desulfurization units are projected to be built and operating in 2003 or earlier. This is based on information received from both licensors of desulfurization technology and refiners. Included in these units are a CDTech unit at Motiva's Port Arthur refinery, a CDTech unit at another refinery not yet publicly identified, two Black and Veatch units at smaller refineries, one Phillips S-Zorb unit, and 2-5 additional units at major refineries desiring to reduce sulfur early. The two CDTech projects are expected to be operational in 2000, while the Black and Veatch and Phillips projects are expected to be operational in 2001 and 2002. The additional units are projected to be operational in 2002 and 2003.

These pre-2004 desulfurization units will also provide a source for early sulfur reduction credits. Based on the production volumes and sulfur levels of the refineries projected to receive these projects, we project that these new units will reduce national average sulfur levels by 1 ppm in 2001, 29 ppm in 2002, and 29-51 ppm in 2003. These projections are based on:

- Two refineries (representing about 1.0% of non-California gasoline production) installing CDTech and Octgain 220 desulfurization units in 2000 which reduces half of its gasoline to 30 ppm,
- Three refineries (representing about 1% of non-California gasoline production) installing absorbent desulfurization units in 2001 and 2002 to produce 30 ppm gasoline in order to demonstrate this technology,
- Two to five refineries (representing about 3-8% of non-California gasoline production) installing absorbent desulfurization units in later 2002 and 2003 to produce 30 ppm gasoline in order to generate early sulfur credits and allotments,
- The baseline sulfur levels for these refineries range from 130-700 ppm; on average, the baseline sulfur level is roughly 350-400 ppm.

On an annual national gasoline pool basis, these annual credits sum to a total of 59-81 ppm of credit. Ignoring the small increase in gasoline consumption annually, operating at 90 ppm in 2005 will require that refiners use 60 ppm of credits relative to the 30 ppm refinery average standard. The credits which can be used by small refiners beyond 2005 are very low, due

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to their small production volumes and amount to less than 5 ppm. Thus, these early units will either provide all of the credits which are needed in 2005 and beyond, with roughly 15 ppm of credit to spare, or will fall less than 5 ppm short.

In addition to credits from new plants, refiners can generate credits operationally, as discussed above. Eliminating the 5 ppm shortfall would only require that annual average sulfur levels from 2000-2003 be reduced by 1 ppm on average. Routing heavy FCC gasoline to reforming hydrotreaters has far more potential to reduce sulfur than 1 ppm on average. Also, as mentioned above, sulfur levels in 1998 were significantly below those of 1997. Given that refinery's baselines will be based on their 1997-98 average, many of these refineries can generate credits if they can continue producing gasoline at their 1998 levels. This approach could generate more than 15 ppm of credit per year, well above that needed to complement credits generated from new desulfurization units, even if refiners did not trade all of the credits that they generated.

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